WESTERN AREA POWER ADMINISTRATION

SIERRA NEVADA REGION

The Central Valley Project – Rate Order WAPA – 194
Notice of Proposed Formula Rates for Energy Imbalance Market Services, Sale of Surplus Products, and Revisions to Existing Energy Imbalance and Generator Imbalance Rate Schedules.

Public Information Forum August 17, 2020

9:00 A.M.

Web Ex

WESTERN AREA POWER ADMINISTRATION

114 PARKSHORE DRIVE FOLSOM, CALIFORNIA

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DATE: Monday, August 17, 2020

TIME: 9:00 a.m.

LOCATION: Web Ex

REPORTED BY: Gigi Lastra, Notary Public

JOB No.: 4219269

A P P E A R A N C E S

Koji Kawamura , Attorney-Advisor

Amy Burrow

Ansel Lundberg

Bill Hughes

Brian Schinstock

Bruce McLaughlin

Bryan Crabtree

Carl Dobbs

Cary Fox

Dave Olivares

Frank DePalma

Fred DeAnda

Frederick Jones

Howard Hirhara

Jarrod Czinski

Jeff Fruit

Jim Shetler

John Cummins

Josh Blake

Kelly Campbell

Lena Perkins

Melinda Rolo

Michelle Gonzales

Nicola Costello

Padmini Palwe
Piyush Amin
Regina Rieger
Richard Buckingham
Roberta Roberts
Rodney Bailey
Rosemary Jones
Sandee Peebles
Scott Baker
Stephen Mariani
Tasnim Aslam
Vela Wann
Tong Wu
Willie Manuel

P R O C E E D I N G S

KOJI KAWAMURA: All right, we can go ahead and go on the record now.

AUTOMATED VOICE: This meeting is being recorded.

KOJI KAWAMURA: Good morning and welcome to WebEx for Western Area Power Administration public information forum on the proposed formula rates for the energy imbalance market services, sale of surplus products, revisions to existing energy imbalance and generator imbalance rates schedules. Rate order WAPA 194.

My name’s Koji Kawamura, and I’m an attorney with the office of general counsel, and I’m going to be providing as the moderator for today’s information forum.

Before we start the presentations, I want to address a few housekeeping issues. I want everyone to be aware that a verbatim transcript of today’s forum is being prepared by our court reporter. Everything being said while we are in session today together with all documents presented will be part of the official record.

You can purchase a copy of today’s transcript directly through the court reporter. The

court reporter's name, address and telephone number will be available from WAPA upon request. Copies of the transcripts will also be available for review at WAPA's Sierra Nevada customer service regions as well as on the public rates websites.

Because of COVID, we're still avoiding large in-person meetings, and I want to thank everybody for attending this virtual meeting. Given the logistics of large virtual meetings, to avoid microphone feedback, we're muting everyone but the speaker.

If you have any questions, please use the chat feature on the WebEx or raise your virtual hand. We will open up the lines after each of the speakers is done, so if you're on the phone you can ask questions.

In addition, if you had chat questions or if you raise your hands we'll take those questions at the end of the presentation. The way we'll kind of do those is we'll take the questions of the people who have asked questions in chat, then we'll take those raised hands, and then finally we'll open up the phone lines.

I want to make sure that we get an accurate attendance of today's proceedings and so for

hose individuals who have signed in via WebEx, we already have your name and organizations you represented. For those people who've dialed in, we're going to go ahead and open up the telephone lines now so you can introduce yourselves. Please give your name and the organization you represent. Tony, if you can go on ahead and open up the phone lines now so we can get an introduction of the folks who are on the phone.

TONY HENRIQUEZ: Okay. So, the first person that I'm going to unmute looks like their phone number -- it doesn't give me the last four, it gives me the first six. So, their phone number starts with 916-781 and I know that's going to be pretty general so I'm going to unmute that person and see if they can speak. Well, it's not giving any option to unmute him. Awesome. Let me close this panel and start -- see if it gives me a better panel. Sorry about that.

Sorry, working my way through this portion. Great. Okay. I apologize for that. It's just not giving me the option to...

KOJI KAWAMURA: Tony, well, I'll let you try to figure that out and we will give people the opportunity on the phone to introduce yourselves here once Tony figures that out and we'll try again in a

little bit. But I'm going to go ahead and proceed. Most, if not all of you, should've received a letter or email for WAPA informing you of today's public information forum.

WAPA also published a notice of today's information forum in the July 31, 2020 Federal Register, Volume 85, Page 46803. Notice was also published on WAPA's website.

We are meeting today, August 17th, for this information forum. In today's information forum, WAPA will present the proposed formula rates for the energy imbalance market services, sale of surplus products and revisions to the existing energy imbalance and generator imbalance.

I want to note one modification to the Federal Register notice. The Federal Register notice stated the proposed rate will go into effect on April 1, 2021. After the publication of the notice, the Balancing Authority of Northern California and California ISO approached WAPA and requested to move up the EIM implementation to March 25th. WAPA's rates manager will provide more details about this in her presentation. Given the need to move up the implementation date, WAPA proposes that the effective date will now be March 25, 2021, instead of April 1,

2021.

WAPA will continually update its rates webpage to provide you the most up to date information. If you're interested in following this process, please refer to WAPA's webpage to stay up to date. As noticed in the Federal Register, on WAPA's webpage, WAPA will hold a public comment forum later today, August 17, 2020. The comment forum will start at 1 p.m. You may hold your comments for the comment forum or you may submit your comments in writing at any point during the comment period. The comment period ends on October 29, 2020. All comments must be received by that date to be considered.

So, that issue?

TONY HENRIQUEZ: I have. I apologize. It was. So, it's ready to go.

KOJI KAWAMURA: All right. So, I'm going to take this opportunity and we're going to go on ahead and let the people on the phone introduce themselves.

TONY HENRIQUEZ: Okay. Again, I have unmuted phone number 530-209.

BRIAN SCHINSTOCK: That might be me. Brian Schinstock with Roseville.

TONY HENRIQUEZ: Will you say your name

again, please?

BRIAN SCHINSTOCK: Yeah. Brian Schinstock.

TONY HENRIQUEZ: And can you spell your last name?

BRIAN SCHINSTOCK: Yep. S-C-H-I-N-S-T-O-C-K.

TONY HENRIQUEZ: Thank you. Okay, I'm going ahead and unmute the next phone-in caller, and it looks like the phone number starts with 530-220.

DAVID TROMBLEE: David Tromblee from U.C. Davis.

TONY HENRIQUEZ: Thank you, David. And the next numbers looks like their number starts with 530-941. So, call in user 530-941? If you are muted, just in case you are muted -- double-muted on your end, I don't hear anything. Okay. I guess we can try him again later, Koji?

KOJI KAWAMURA: Yeah, that's fine.

TONY HENRIQUEZ: Okay. That was the only three call-in numbers that I show on the screen.

KOJI KAWAMURA: All right, thank you, Tony. At this point I'm going to go ahead and introduce WAPA's panel, and as we go through the presentation, please hold your questions for the end.

At the end of each presentation we'll give people the opportunity to ask questions and comments.

And, again, the panelists for today are Arun Sethi, who is WAPA's power marketing manager, Autumn Wolfe, who is WAPA's rate manager, Tong Wu, settlement manager, Robert Delizo, resources and scheduling manager, Rosemary Jones, power marketing advisor, and we also have a panel of subject matter experts who will be standing by to help answer any questions. And with that, I'm going to go ahead and turn this over to Autumn, who will be doing the first presentation -- unless Arun, do you want to say something first?

AUTUMN WOLFE: Okay, I will get started here. Thank you, Koji. As Koji mentioned, my name is Autumn Wolfe and I'm the rates manager here at WAPA's Sierra Nevada region. I'll be presenting on several different topics throughout the presentation this morning. First, I'd like to start with just a few WebEx housekeeping items prior to walking us through the morning agenda.

So, most of this Koji already covered but before starting, I'd like to just let everybody know that the agenda and today's presentation are attached to the calendar invitation for this morning's

meeting just in case you're not able to join the WebEx on your computer.

Also, the agenda and the presentation are posted on our WAPA rate case website as well. So, those are two places you can find the presentation that we're going through this morning.

So, for the WebEx housekeeping items, like we said, Koji mentioned that when you log on, you're automatically put on mute and that there'll be time for questions at the end of each section of the presentation, so we make sure we pause to get everybody an opportunity to ask any clarifying questions they may have.

And there's one of three options you can use for asking your question: You can send your questions to the host using the WebEx chat feature, you can raise your hand by pressing the raised hand icon next to your name in the participation list, or if you're participating by phone, when prompted we'll open the phone lines for you to ask your question. And if you are on the phone, you may have to press star-6 from your phone to unmute yourself.

So, some questions you might have may be answered in other portions of the presentation but please feel free to ask your questions as we go along

at the end of each portion. We should have time for additional questions at the end of the meeting, so there will be that opportunity as well.

And then just a reminder. When you are asking your questions, make sure you're not double-muted. As we mentioned, when you log on, you're muted and then when we open your phone line for you to speak and ask your question you might have to hit star-6 as well to unmute yourself again. We call it double-muting. We want to make sure that we hear you when you have your question. Next slide.

For today's agenda, we already heard opening remarks from Koji, and I just walked you through the housekeeping items. I'll also be presenting on our rates process timeline, and then I'll give a brief overview of the California Independent System Operator EIM.

Then I'll talk about EIM implementation's ongoing costs and the allocation of EIM charges before turning the presentation over to Dr. Tong Wu, our settlements manager, who will share more specific information on the different EIM charges that could be allocated to WAPA.

Then we will learn about EIM resource valuation from Robert Delizo, our resources and

scheduling manager before I present again on the proposed formula rates. Then we will have Rosemary Jones, our power marketing and energy services specialist share information on the sale of surplus products. And then we will hear form Robert Delizo again for him to share information on EIM generation dispatch ranges.

At the end of the presentation I'd like to share some web links with you about where you can find additional EIM resources, and then Koji will have closing remarks for us. Next slide. Okay, so before we jump into the main portion of the presentation, I'd like to share with you our rate process timeline. Next slide.

On July 31st we posted our proposed federal register notice, which kicked off our 90-day comment period for rate case 194. And today, as Koji mentioned, is our public information forum this morning, and this afternoon we have the public comment forum beginning at one, and that will go until all comments are received, but no later than 4 o'clock this afternoon.

October 29th is the end our 90-day comment period for rate case 194 and we anticipate that sometime in February, I would say mid-February,

our final federal register notice will be published for rate case 194. And then as Koji mentioned, March 25, 2021 is the new -- is when our new rate schedules become effective and we are live in EIM -- in the EIM market.

So, for more information we do have a formal calendar posted to our website at the link that's on the screen, and this is just a good place where you can go to reference where we're at in our proposed timeline. Sometimes there's a little bit of shift in dates, but the calendar we have posted online has more specific details regarding our timeline. Next slide.

Okay, we're going to start today's presentation with a very high level overview of the California Independent System Operator Energy Imbalance Market, or EIM as we call it. Next slide.

EIM is a real-time energy market so it will not impact our day ahead program. It allows members to buy and sell power close to the time when electricity is actually consumed; it allows us to find the lowest cost resources across the larger region to meet our power needs, and this could potentially reduce our costs. It provides economic benefits to participants because it allows us to dispatch the

least cost resources. And it gives us full visibility of transmission and generation outages, which allows us to manage congestion better on transmission lines, and this provides reliability. More information about EIM can be found on our website at the link that we have on this slide in case you wanted to look up some additional information. Our website has quite a bit more detail on EIM and why WAPA's participating in the energy imbalance market. Next slide.

For this portion of the presentation we are going to share information with you regarding the EIM implementation and ongoing costs. Next slide, please.

To begin the discussion on EIM implementation ongoing costs, we will start with describing the implementation on ongoing costs that WAPA will receive from the Balancing Authority of Northern California, or BANC, as we call them. BANC is considered the EIM entity, and WAPA is an EIM participating entity under BANC. So, BANC has had two phases for implementing EIM. For phase 1, SMUD joined EIM back on April 3, 2019 and paid for all the costs related to implementing EIM at that time.

For phase 2, which will be implemented

on March 25th, WAPA made the decision to join EIM along with three other entities: City of Redding, Roseville Electric Utility and Modesto Irrigation District. Since SMUD paid all of the EIM implementation costs for phase 1, and the phase 2 EIM participants will be using some of those systems that were initially paid for by SMUD, WAPA as well as the other three participating entities are responsible for sharing in some of those phase 1 implementation costs. In addition to implementation costs, BANC will also have annual ongoing costs associated with participating in EIM that all participating entities will end up sharing and paying. Next slide.

On this slide we share the different type of implementation and ongoing costs that WAPA will be allocated by BANC. There will be implementation or startup costs such as SMUD support. So, SMUD manages the EIM for BANC, so there are costs associated with that support. There's OATI software upgrade to integrate WAPA into the BANC EIM entity scope. Settlement software upgrade, to integrate WAPA into BANC's EIM scope. Utility project oversight. We have a project manager on site to provide project support and coordination to us. CAISO fees, which include uplift and load-related

charges. Legal support provided to BANC. And then phase 1 reimbursement.

This is WAPA's share of cost incurred during phase 1 for creation of the EIM entity. As I mentioned on the previous slide, SMUD was the first entity to into EIM and paid all the cost to develop the EIM entity. So, those of us entering EIM as part of phase 2 were responsible for a share of those phase 1 costs.

Then we have ongoing or reoccurring costs, such as WEIM operation costs, this is for staffing and software support for EIM operations. And then we have stakeholder support costs for engagement in the EIM stakeholder process. And then, similar to what we saw for implementation cost, we'll have ongoing costs for CAISO fees, which could be like uplift charges and load-related charges. And then, of course, legal support that's provided to BANC. Next slide.

Now we want to talk a little bit about the methodology that BANC will use to allocate costs to EIM participants. BANC has approved a cost allocation methodology to allocate EIM implementation and ongoing costs based on a participating entity's three-year rolling average of their net energy load

percentage, or NEL percent, as we call it. This methodology is used to mitigate for any significant changes in hydrology from year to year.

To memorialize the use of this methodology there is a proposal to revise the BANC EIM participating agreement that participant, including WAPA, has signed. For BANC's allocation of implementation cost for phase 2, WAPA is one of four participating entities, as described in the previous slide.

There's City of Roseville -- I'm sorry, City of Redding, Roseville Electric Utility, Modesto ID, and WAPA. And all four will share and pay the cost for phase 2 implementation. WAPA's net energy load percentage for allocating implementation cost is 24.1 percent, and this is based on a three-year rolling average of information from 2017, 2018 and 2019. For the allocation of ongoing costs, WAPA is one of five participating entities because now we're adding in SMUD, who is also an EIM participant under BANC. And all five entities will share in paying the ongoing cost for EIM. WAPA's NEL percent for allocating ongoing cost is 8.6 percent. Again, this is based on a three-year rolling average of WAPA's NEL percent. The only difference in the net energy

load percent calculation for allocating implementation cost and ongoing cost is whether SMUD's net energy load is included as a basis for allocating cost. Next slide, please.

WAPA's net energy load percent for allocating BANC charges includes the following -- loads for the following entities, which are Lawrence Livermore National Lab, Tracy Pump Load, Trinity Public Utility District, the Balancing Authority Losses and Station Service, East Contra Costa Irrigation District, Contra Costa Water District, Byron-Bethany Irrigation District and San Juan Water District. Next slide.

To get into the more specific details on BANC's annual estimated implementation cost we want to share this slide with you that shows the implementation cost incurred for 2019 and then what is estimated for 2020 and 2021. We have a total cumulative cost of about 1.3 million. And then for 2019 we incurred cost of a little over -- well, it's about 474,000. And then estimated costs for 2020 are about 597,000. And then, as we can see, in 2021, implementation costs start to taper off because we are preparing to go live as of March 25, 2021. And then we'll start to see ongoing costs. So this allocation

of cost that's reflected in this table is WAPA's allocated share of the implementation cost using our net energy load percent of 24.1 percent. And the repayment of implementation costs are spread over three years, as we can see in the table. So, we already incurred the cost for 2019, and then, course, 2020 and 2021 are estimates. Next slide, please. To get into more specific details on BANC's annual estimated ongoing cost, this slide shows that the total estimated cost will be, approximately, 377,000 per year. What's shown here is WAPA's allocated share using our net energy load percent of 8.6 percent. So, as previously mentioned, for ongoing costs, we anticipate they will begin in March of 2021 when we go live in the EIM market. Next slide, please.

In the previous slide we talked about BANC's implementation and ongoing cost, and now we want to share with you the EIM implementation ongoing cost information for WAPA. The only costs we anticipated incurring are for software-based costs. We have total implementation costs that were $545,500. Those costs were actually incurred in fiscal year 2019. And then there are also estimated ongoing costs for about $184,400 per year. And, again, these are related to software-type costs. And these costs will

start to incur in 2021 after we go live in EIM. Next slide, please.

In addition to BANC and WAPA, Reclamation also has EIM implementation cost. Reclamation needs to change their Central Valley automated control system, primarily for software, to accommodate real time dispatch signals for EIM. The current plan is to create virtual units for each EIM aggregation area and the adaptation of the existing automatic schedule and AGC dispatch functions in order to integrate with the new EIM signals. The full scope of changes aren't known yet until decisions on aggregation are made.

For now, placeholder funding of about $500,000 per year for the CVACS-EIM changes are included in fiscal year 2020 and fiscal year 2021, and these placeholders have been approved by the Technical Committee to support this project. These are one-time costs and Reclamation does not anticipate to have any reoccurring ongoing costs related to EIM. Next slide.

To wrap up this section of the presentation we wanted to bring all of the implementation and ongoing costs together for BANC, WAPA and Reclamation to show the total estimated EIM

cost per year. So, that's what we're trying to display in this table here. In the table, the first two rows are for BANC. So, we show BANC EIM implementation costs and then BANC ongoing costs. The next two rows are WAPA's cost for implementation and ongoing costs. And then we have Reclamation's implementation cost. You can see for 2019, total costs were about a little over a million dollars. The estimate for 2020 is, again, a little bit over a million dollars.

And then 2021, the estimate increases a little bit to about 1.3 million. But then starting in 2022, that's when we're done with paying the implementation cost and we're only paying the ongoing reoccurring EIM cost. So the total cost will be reduced down to about half a million or so per year going out into the future for EIM.

To give you an idea of the fiscal impact of WAPA's participation in EIM, we added a section toward the bottom of the table that shows how much of WAPA's O&M is anticipated to increase each year to (inaudible) participate in EIM. So, we can see that in 2019, the increase to WAPA's annual O&M was a little under a 1 percent increase. And for 2020, we anticipate there to be about 1 percent

increase for O&M. And then in 2021, we do see a slight increase -- to our O&M, a little bit over 1 percent and that's because we're going to start seeing the ongoing costs coming onboard. We're going to see the implementation costs taper off and then ongoing costs come on.

In this table we reflect a full year of implementation costs for 2021 but actually it's going to be half because we're only going to have six months for that fiscal year where we're actually participating in the EIM market. So, that 1 percent increase in O&M is going to be a little bit less because we won't have a full year of implementation cost in 2021.

And then in 2022, where we're only looking at ongoing costs for EIM, we see that the impact to O&M is less than half a percent for each year going out into the future. And then at the very bottom of the table we show the fiscal impact of EIM on the annual power revenue requirement that is paid by our first preference and base resource customers. So, we wanted to make sure that we reflect how much our power revenue requirement could potentially increase as a result of our participating in EIM.

So, for fiscal years 2019 and 2020, we

don’t show any impact to the power revenue requirement because we made a commitment to our customers that we would hold EIM-related costs out of the power revenue requirement until we went through this public process where we share a proposal for how we intend to allocate EIM costs.

So, we made an agreement to not include those costs for those power revenue requirements. So, starting in 2021, that’s when we start incorporating proposed EIM implementation costs and proposed ongoing costs. So, you can see that there is an increase projected for the power revenue requirement of about 1.85 percent, and this increase has a lot to do with the implementation cost from previous years that did not go to the PRR. They’re now being included in 2021 because we anticipate being done with this public EIM process.

So, those prior year costs are now included in 2021 so that reflects more than just one year of EIM implementation cost in that increased percentage.

And then in 2022, implementation costs are done and we’re only looking at ongoing cost. And so, the increase in the power revenue requirement is a little bit more than half a percent going out into

future years. Right around .74 percent.

And I just want to point out that this table only reflects administrative type costs, not EIM load charges or any potential benefits that WAPA may receive from participating in the energy imbalance market. So, we'll learn more about load costs and EIM benefits in other portions of today's presentation, but I just wanted to make sure it's understood that this impact to O&M and the impact to the power revenue requirement is only showing a cost piece for administrative charges. It does not include load-based costs or any benefits we might see from participating in EIM.

So, this brings us to the end of this portion of the presentation, and so I would like to turn it back over to Koji to see if there are any questions from anybody that's participating today.

KOJI KAWAMURA: Thank you, Autumn. At this point in time, I'm going to go on ahead and if you have any questions, either you can throw them in the chat or you can raise your hand. I don't see any questions in the chat, and so, Tony, do you see any raised hands?

TONY HENRIQUEZ: No, I don't see... I have a feedback column and I don't see any raised

hands there, and I have not received any texts.

KOJI KAWAMURA: Okay. All right, so at this point I am going to go on ahead and briefly open up the phone lines in case anyone has a question they want to ask. So, if the questions don't work well on the phone line and there's too much static, you know, we'll go line by line if we have to. But, really, if you can either put your questions in the chat or raise your hand at this point in time -- Tony, go on ahead and open up the phone lines to see if anyone has any questions.

TONY HENRIQUEZ: Okay. So, prior to me opening up the phone lines, I'm going to let you know that I did receive a text from Jim Shetler and he would like to ask for some clarifications. So, I'm going to go ahead and unmute Jim Shetler right now. Go ahead, Jim.

JIM SHETLER: Good morning. It's Jim Shetler with BANC. I did want to offer a slight clarification. On the ongoing costs for EIM, the annual costs, the $376, there's an updated budget that is in the process of being discussed within BANC And will be improved later this year. It actually lowers WAPA's share a little bit.

But the $300 range is for the nine

months of 2021. So, when you start talking annually thereafter, then that would be increased by another 25 percent or so. So, it's probably somewhere in the $400-$450 range. I just wanted to make sure that you were aware of that.

KOJI KAWAMURA: Thank you, Jim.

AUTUMN WOLFE: Yes, thank you for providing that clarification. That's very helpful. And I'm going to make sure I update my notes and make sure I update that particular side. Thank you very much.

KOJI KAWAMURA: All right, so, Tony, do we have any other questions?

TONY HENRIQUEZ: Yes, we do. But did you want me to go ahead and go to the phones first since we offered that?

KOJI KAWAMURA: Yeah, that's fine.

TONY HENRIQUEZ: Okay. Right now I'm going to go ahead and unmute 530-209. And I think 530-209, did you have any questions?

BRIAN SCHINSTOCK: I do not, no.

TONY HENRIQUEZ: And will you remind me again what your name is? I apologize. Then that way I can make sure I'm not addressing you by a phone number.

BRIAN SCHINSTOCK: Yeah, no problem. Brian Schinstock.

TONY HENRIQUEZ: Thank you, Brian. Okay, and then I've got 530-941. I've unmuted you. If you're call-in user number 14 -- excuse me, number 5, phone 530-941, you are unmuted, in case you're muted on your end. Did you have any questions? Okay.

And then I don't see our third phone number in here. They might've dropped off or changed their process. So, we do have one other question from Mr. David Tromblee. I'm going to go ahead and unmute him. Interesting, it's not letting me unmute him. Okay. Go ahead, David, now I see you're unmuted.

DAVID TROMBLEE: Thank you. I was just wondering if the idea of implementing EIM sounded like it was having to do with savings, potential savings, but it only seems to show in this chart that there's just an increase in the power revenue requirement. I'm just wondering if there are savings, where would those be accounted for, and would we expect savings or just costs?

AUTUMN WOLFE: That's a very good question. Thank you for asking that. So, yes, we do anticipate that there will be benefits from our participating in the energy imbalance market. And

while we are proposing that the costs related to implementation of EIM and then ongoing costs for participating in EIM will go to the power revenue requirement, any benefits from us participating in the energy imbalance market will also flow through to the power revenue requirement. And it's our hope that the benefits we see from participating will offset the costs of implementation and ongoing cost. That's what we're hoping for.

Later on in the presentation, we will share a little bit more information on the benefits of our participating in EIM so that you get a better idea of how much those benefits might look like that are going to potentially be applied to the power revenue requirement, and that will hopefully offset any EIM implementation and ongoing costs. So, more to come. Thank you.

DAVID TROMBLEE: Thank you.

KOJI KAWAMURA: Okay. And then I have a question from Randy Howard. And I see that Mr. Dave Oliveras also has his hand raised. So, I will come to you here shortly, Dave. Let me go ahead and get Mr. Randy Howard with his question as well. Go ahead, Randy. Randy, in case you're muted on your end, I can't hear you.

RANDY HOWARD: I was muted. I'm sorry. He's barking away. Thank you for the opportunity. Is WAPA planning on hiring any additional staff or hear of Reclamation -- hiring any additional staff to support the implementation for the ongoing operation regarding the EIM?

AUTUMN WOLFE: So, thank you for that question. No, we are not anticipating hiring any additional staff for the implementation of EIM and then for the ongoing -- the ongoing activities related to EIM. Those activities are going to be absorbed with the duties for existing staff that we already have. We don't anticipate hiring anybody additional. And that's my understanding for Reclamation as well.

They intend to absorb the EIM duties as part of their existing staff. They're just being added to all the activities we currently are working on. So, no additional labor charges related to EIM. We will just absorb it with our current labor staff.

RANDY HOWARD: And so are you then shifting some of the cost structure of your existing staff so they'll charge to EIM implementation and ongoing costs?

AUTUMN WOLFE: So, what will happen is -- right now, labor cost for our existing staff is

charged as annual O&M on our power revenue requirement. And so any labor charges associated with EIM that the staff provides support for, their labor will still continue to be charged to the annual power revenue requirement and it will still show in the annual O&M for WAPA. So, they may be working on EIM instead of other activities but it will still reflect as a labor cost within the annual O&M for WAPA. Does that make sense?

RANDY HOWARD: Well, my concern with how you just responded is, you know, we won't have a breakout understanding of the labor cost structure regarding EIM implementation and ongoing costs. So, when you get to the benefit side of -- you know, how benefits are allocated and shared, we don't know -- you know, if everybody is paying in because we all take our share of the ongoing labor costs, I don't know that it's going to be the proper distribution or allocation of the benefits.

So, I would like for at least WAPA to consider a separate charge code for those that are completely labor costs so we can really just understand what is this costing? And then when you get to the benefit side on the allocation of those benefits, we can have a better understanding there.

AUTUMN WOLFE: Sure. Absolutely. So, just so you know, we have developed separate labor codes for when we do work on EIM and so we can provide that detailed information. And we know for after the first couple of years of implementation that it would be of interest to our customers to share that detailed level of information.

And so it was our intention that at future customer meetings, that we would give a breakdown of what EIM labor charges were for the year and, you know, whatever EIM-related costs were incurred. And then, of course, share what benefits we saw from participating in the EIM, and then just provide a net calculation. Was it a net cost for the year, or was there a net overall benefit for the year?

So, we anticipate that that would be something our customers would be interested in, so we're going to make sure that we have reporting through our software system that will allow us to pull costs at that level of detail so we can share that information with customers at future customer meetings.

RANDY HOWARD: Thank you, Autumn. That's perfect.

AUTUMN WOLFE: Sure, no problem. And

thank you for the question.

TONY HENRIQUEZ: So, next one up, I have Mr. Dave Oliveras. I'm going to go ahead and unmute you now. Go ahead, Dave.

DAVE OLIVERAS: Okay. Can you hear me, Tony?

TONY HENRIQUEZ: I can.

DAVE OLIVERAS: All right, great. Autumn, thank you so much for walking us through all of this information. I just had one quick question just -- I'm trying to figure out if there's a distinction here. I thought I heard you say that the ongoing -- implementation and ongoing cost wouldn't be charged until after the proceeding was completed. But I'm trying to figure out here if it's a 2021 estimate, does that mean it's going to be included in the PRR starting October 1st? Maybe that's -- I just wanted a little clarification on that.

AUTUMN WOLFE: Yes, sure, no problem. So, yes. So, the implementation costs that would have hit in 2020, those will be included in the 2021 power revenue requirement. They're already included in the forecast that we have posted on our website, and so they are reflected in the total O&M -- annual O&M for WAPA.

DAVE OLIVERAS: Okay, so they are going to come in this fall and then we're going to -- give us through next September?

AUTUMN WOLFE: That's right. And we anticipate -- and we anticipate that the increase to the power revenue requirement will be about 1.85 percent.

DAVE OLIVERAS: Okay, thank you. I just wanted to make sure there was that distinction. Thank you very much. Appreciate it.

AUTUMN WOLFE: Sure, no problem. Thank you.

TONY HENRIQUEZ: Okay, so the next question I have is from Willie Manuel. I'm going to go ahead and unmute you right now, Willie, and you're unmuted.

WILLIE MANUEL: So, thank you. Good morning. And thank you, Autumn, for going through this presentation. I just had a couple questions. The first one -- I think earlier in the slides it was said that, you know, implementation costs were going to be paid by the participants. But then in here, in this slide 20 here, it seems like the implementation and ongoing costs are going to be included in our revenue requirements, which is paid by all -- I guess,

preference customers. So, can you clarify that a little bit?

AUTUMN WOLFE: Sure, sure. That's a good question, actually. So, when I say all EIM participants will pay for EIM ongoing costs, I'm talking about participating entities. At the beginning of this portion of the presentation, I explained that BANC is the EIM entity, and then WAPA, SMUD, Roseville, Redding and MID are all participants participating in EIM under BANC, as the EIM entity.

So, all of those participating entities, including WAPA, will share in paying the ongoing costs. So, for WAPA's share of those ongoing costs, what we do is we sub-allocate those costs for repayment, and so those costs are sub-allocated to our power revenue requirement, which will be paid by our first preference and our base resource customers. And the next portion of the presentation gets a little bit more into those details for how those costs are going to be allocated.

But one thing I want to make sure is clear is that we spent a lot of time talking about how charges are going to be allocated to the power revenue requirement but I want to make sure that it's clear that any benefits WAPA receives from

participating in the EIM will also go to the power revenue requirement. And so we get into more detail later in the presentation that explains what those EIM benefits might look like. And, again, it's our hope that the benefits from participating in EIM will be more than enough to offset any charges that we see for EIM implementation and ongoing cost. So, that's the goal.

WILLIE MANUEL: Thank you. I've got a follow-up question that's related to that hope, I guess. So, you know, you mentioned that the hope is that the benefits will be greater than the costs. How often -- and you might have answered this earlier -- how often would WAPA look at -- you know, compare the costs against the benefits? And then if the costs are greater than the benefits, you know, how long before -- will WAPA consider stopping participation with the EIM if the benefits are not -- don't cover the costs?

AUTUMN WOLFE: So, there are many reasons why we are participating in EIM. One of them is, hopefully, cost savings but it's also so that we have trading partners among other -- there's other reasons as well. There are both fiscally beneficial and intangible benefits from our participating.

And so until we actually participate in

the market, we can't say for sure what our load-based charges are going to look like. We can't say for sure what our -- what benefits we might receive for participating in the market.

So, when I say we hope the benefits will more than cover the cost of EIM implementation and ongoing cost, it's because we really -- we don't really know what we're going to see until we're actually participating. So, we don't want to say that for sure this is going to happen when we just, frankly, don't know.

And, as you know, with any time you start something new, you know, it might take a while to find your feet when participating in the market. And so we may not see a net benefit in the first year or the second year, you know, but we're hoping we will. But it might take time to refine how we participate where we can start seeing benefits that are greater than cost.

So, to get back to the other question you had mentioned, how often would we share this information, this kind of goes back to the question that Randy Howard was asking. We understand that our customers will find this information very interesting.

You guys are going to want us to be

very transparent with EIM costs and benefits, especially for the first couple of years, and we anticipate that at future customer meetings, that this is the type of information that we would share. We would share the EIM labor costs, ongoing costs, administrative costs, load-based costs, and then we would share what benefits we realize from participating.

And then we would do the calculation to show you whether there was a net benefit for the fiscal year or if there was a net cost. So, we intend to be fully transparent in how participating in EIM looks for WAPA, and so we definitely plan on doing that in the future.

WILLIE MANUEL: Thank you.

AUTUMN WOLFE: Sure.

TONY HENRIQUEZ: Okay. So, I'm scrolling through our attendee list and I don't see any raised hands. Oh, hang on, I have one from Ms. Regina Rieger. Let me go ahead and unmute you, Regina. Go ahead, Regina.

REGINA RIEGER: Thank you. Thank you for your presentation today, Autumn. Very helpful. Back on slide 14 you referenced that the ongoing and implementation costs are measured now on a three-year

rolling average of net energy load percentage, which is, I think, a good change from what was originally proposed to use in 2017 as a basis.

Just a point of clarification. Is that an ongoing rolling three-year average for the prospective cost?

AUTUMN WOLFE: Yes. This is a three-year rolling average going forward.

REGINA RIEGER: Thank you.

AUTUMN WOLFE: You're welcome.

TONY HENRIQUEZ: Okay, again, scrolling through, I don't see any other feedback other than Ms. Rieger. If you don't have any other questions, please go ahead and un-flag your raised hand, otherwise I can go ahead and unmute you again. Okay, good, thank you. I don't see any other raised hands and I don't have any other texts in my box for chat.

KOJI KAWAMURA: Okay, thank you, Tony. So, with that, let's go on ahead and move to the next presentation.

AUTUMN WOLFE: Great. Thank you, Koji. So, for this portion of the presentation we get into the details for how we're going to allocate EIM charges. Next slide, please.

Okay, so this first slide shows a

flowchart that gives an overview of how EIM charges will be allocated. For this portion of the presentation, we'll break down this flowchart into smaller pieces and share the details for how implementation and ongoing charges will be allocated. Next slide, please.

First, we'll start with the allocation of EIM implementation costs. As we talked about in the first section of this presentation, there are implementation costs required for participating in EIM for BANC and WAPA and Reclamation. The current proposal is for the EIM implementation costs to flow through to the power of revenue requirement for payment.

This proposal is based on the understanding that any benefits from WAPA participating in EIM will also flow through to our power revenue requirement. And as I mentioned previously, our hope is that benefits will exceed the participating and ongoing... I'm sorry…the implementation and the ongoing cost for EIM. Next slide, please.

So, this slide shows how EIM implementation costs will flow through to the power revenue requirement. Reclamation's implementation

costs will come to WAPA and then we will also have WAPA's implementation costs, and then WAPA's share of BANC's implementation costs that are all allocated to the power revenue requirement.

So, in this flowchart we see Reclamation's implementation costs of about a million dollars, it'll come to WAPA. And then we have WAPA's implementation costs of $545,500. And then we have WAPA's share of BANC's implementation cost. This is based on our NEL percent of 24.1 percent, and the total anticipated implementation costs are right about $1.3 million. So, those costs will go to the power revenue requirement, which is paid by our first preference and base resource customers. Next slide.

And now for the rest of this portion of the presentation we're going to focus on the allocation of ongoing charges. As we talked about, there will be ongoing EIM charges for BANC and WAPA while participating in EIM. The proposed process for allocating ongoing EIM charges depends on whether the charges are for conforming or nonconforming loads.

For conforming loads, the proposal is to allocate WAPA's share of EIM charges to transmission customers who are subject to WAPA's tariff, including WAPA Merchant, based on load ratio

share percentages. Also for conforming loads, there is a tier 1 and a tier 2 allocation for allocating charges.

For nonconforming loads, the proposal is to directly allocate EIM charges to the customer with the nonconforming load. Also, we would like to share that for EIM charges related to project use, WAPA has a statutory obligation to provide generation to project use customers first. Therefore, under this current proposal, load costs for project use customers will be allocated to the power revenue requirement for payment. Next slide, please.

As I mentioned on the previous slide, for the allocation of ongoing costs, the process used for allocating the costs depends on whether the load is for a conforming load or a nonconforming load.

Conforming loads are usually associated with a weather-based element, which is somewhat predictable based on the given conditions. And for conforming loads, for entities within WAPA's sub-balancing authority, those loads will be submitted to CAISO by BANC using BANC's scheduling coordinator ID. So, WAPA will provide the load information to BANC, who will then submit the information to CAISO on our behalf. Then there are the nonconforming loads which

are loads that change and are abnormally different than the normal load patterns, such as a factory that has high energy demands at different times throughout the day. For nonconforming loads within WAPA's sub-balancing authority, those loads will be submitted to CAISO directly by WAPA using our own scheduling coordinator ID. Next slide, please.

I mentioned previously that for conforming loads there is a tier 1 and a tier 2 allocation of EIM charges. A tier 1 allocation is the allocation of WAPA's share of CAISO and BANC charges to WAPA's transmission customers that are subject to our tariff, including WAPA Merchant.

For the tier 1 allocation of EIM charges, new EIM rates schedules are required and they only apply to WAPA's transmission customers that are subject to our tariff, including WAPA Merchant. WAPA Merchant is considered a transmission customer. Then there's the tier 2 allocation, which is the sub-allocation of CAISO and BANC charges from WAPA Merchant to the annual power revenue requirement, which is, as I mentioned previously -- which is paid by our first preference and our base resource customers. Next slide, please.

Now I'd like to walk you through the

portion of the overall flowchart that we saw at the beginning that shows the process for allocating charges for conforming loads. This specific portion of the flow chart focuses on the tier 1 allocation for conforming loads.

So, as I mentioned for conforming loads, EIM charges flow through BANC. Charges are first allocated from CAISO to BANC, and then BANC allocates the EIM charges among its EIM participating entities based on their net energy load percent. In this flowchart, WAPA is on the left hand side in the green box. WAPA is the transmission provider. And on the left, the kind of blurry green box on the left, and that box represents the other participating EIM entities under BANC. So, that box represents Roseville, Redding, MID and SMUD.

For the EIM charges allocated to WAPA, they are then allocated to WAPA Merchant and WAPA's transmission customers. This is considered the tier 1 allocation. And this tier 1 allocation is where the new proposed EIM rate schedules apply. Later in today's presentation I will share more detailed information on the new proposed EIM rate schedules and then walk you through an example of when the rate schedule applies and how a charge will flow through

from CAISO all the way through to the power revenue requirement. Next slide, please.

Now I'd like to walk you through the tier 2 allocation for conforming loads. The tier 2 allocation is the sub-allocation of charges that are assigned to WAPA Merchant. For this portion of the flowchart, we explain why we are proposing that load charges for customers within our sub-balancing authority are to be allocated to WAPA Merchant and then to the power revenue requirement. The load-based charges that are allocated to WAPA Merchant in the tier 1 allocation are charges for loads within WAPA's sub-balancing authority.

In this flowchart for the tier 2 allocation, the first blue box on the bottom left identifies customers within WAPA's footprint. And any of these customers could incur EIM load-based charges. Two customers within our footprint have load greater than one megawatt. Three customers have load less than one megawatt. Four customers fall within our footprint but are actually within SMUD's sub-balancing authority. So, SMUD will be allocated their EIM-based charges, not WAPA. And then there are two customers that have project use.

For the two customers with load greater

than 1 megawatt, we don't believe that we will get load detail at a granular enough level to identify which load charges belong to which customer because these loads are so small. For the three customers with loads less than 1 megawatt, these loads aren't tagged because they don't meet the 1 megawatt threshold for tagging loads. So we don't believe that we will be able to identify which load charges belong to which customer. And then, of course, there are the two project use customers that we have a statutory to serve their needs first.

So, with not having charge information at a granular enough level for customers within our sub-balancing authority, we're proposing that EIM load charges and any potential benefits -- we propose that they all get allocated to the power revenue requirement for payment.

In the second blue box on the bottom of this flowchart, this second box represents Trinity Public Utility District, who is a first preference customer with load within our sub-balancing authority. BANC and Trinity have developed an agreement that they will pay specific load-based charges for Trinity, and a portion of Trinity's charges will also go to the power revenue requirement. We plan to share more

information on the allocation of Trinity EIM charges in a later portion of the presentation. So, more will come on that allocation.

And then the third blue box on the bottom of this flowchart represents administrative type charges that were described in the first portion of the presentation. And this is just showing how those charges are also anticipated to flow through to the power revenue requirement. Next slide, please.

Now I'd like to walk you through the allocation of charges for nonconforming loads. Earlier I mentioned that for nonconforming loads, WAPA will submit information for these loads directly to CAISO using our own scheduling coordinator ID, and charges will flow through to WAPA directly from CAISO. So, they will not flow through BANC, like we talked about for conforming loads.

The proposal is that WAPA will direct bill customers with nonconforming loads and the charges for project use will -- and the charges for project use for nonconforming loads will flow through to our power revenue requirement, as shown here in the flowchart. Next slide, please. Now we're going to talk about charges related to WAPA's participation in the EIM market. Our current proposal is that both

the charges and benefits will flow through to the power revenue requirement. And as I mentioned earlier in response to a question that was asked, at this time it's really hard for us to say what the charges and benefits might look like for our participation in the market. We'll know more once we start participating.

We anticipate that we would see revenue from dispatch benefits and charges related to generation deviation. Later in the presentation we share more information on what potential EIM benefits might look like. And, again, as we said a couple times throughout the presentation, our hope is that the benefits will offset the cost of our participating in EIM. Next slide, please.

So, on the previous slides we shared the allocation of BANC's ongoing charges, and on this slide we're sharing the ongoing costs related to WAPA's participation in EIM. These are all annual software-related costs that were described in the first portion of the presentation. And as you can see from this flowchart, we are proposing that the software-type costs are allocated to the power revenue requirement. And we will start seeing these costs in the power revenue requirement in 2021 after we start

participating in EIM. Next slide, please.

So, now we're going to bring all the pieces of the overall charge allocation flowchart back together. We talked about a proposal for the allocation of charges for conforming loads, including the tier 1 and tier 2 allocation of charges, which is represented here in the red circle. Next slide.

We talked about the proposal for the allocation of charges for nonconforming loads, which is represented here in the red circle. Next slide.

And we talked about the proposal for allocating charges and benefits related to our participation in the EIM market. Next slide.

And, last, we talked about our proposal for allocating WAPA's ongoing EIM charges. So, this concludes the charge allocation portion of the presentation. The next portion of the presentation we will share more detailed information about the specific CAISO charges that we could see for conforming and nonconforming loads. But before we move on to that portion of the presentation I'd like to pause here and turn it back over to Koji to see if there are any questions for this charge allocation portion of the presentation.

KOJI KAWAMURA: Thank you, Autumn. At

this point in time, Tony, do we have any questions? I don't see any questions in the chat. Do we have any other questions or raised hands?

TONY HENRIQUEZ: I'm scrolling through the attendee list and I don't see any raised hands as of yet. And, like you said, I don't see... Oh, I do have a question from Mr. Willie Manuel. I'm going to go ahead and unmute you. Go ahead, Mr. Manuel.

WILLIE MANUEL: Thank you. Autumn, in some of the areas, you know, you mentioned when you were (sound drops) conforming and nonconforming loads, it seems like you mentioned those are within WAPA sub BA footprint. Now, TID is their own balancing area and we're not in the WAPA (inaudible) footprint. Where do we fit in in these charts, I guess?

AUTUMN WOLFE: That's a good question. So, where you fit in is you are a customer who pays the power revenue requirement. So, customers who pay the power revenue requirement are indirectly impacted by implementation costs for EIM and for EIM ongoing costs. So, the new proposed EIM rate schedules apply to the tier 1 allocation, which is specific to WAPA's transmission customers, who are subject to our tariff, and then also WAPA Merchant.

But as a customer of WAPA Merchant, TID

will be paying load-based charges and administrative EIM charges that flow through from WAPA Merchant to the power revenue requirement. And you'll also share in the benefits that flow through from WAPA Merchant to the power revenue requirement as well.

So, we talked a little bit about how WAPA will participate. We could see dispatch benefits and, of course, there might be generation deviation charges as well. Those flow through the power revenue requirement. And so that's how TID would be impacted, as a customer paying the power revenue requirement -- you'll see those costs flow through.

But, as we mentioned, in future customer meetings we intend to be very transparent and share the total EIM cost that we have incurred on an annual basis and share the total EIM benefits that we've realized, and then share what that impact is to customers that pay our power revenue requirement. We would want to make sure that we're clear as to how everybody is impacted. But to specifically answer your question, you are indirectly impacted by the tier 2 allocation, that we allocate to (inaudible) from WAPA Merchant through to the power revenue requirement.

WILLIE MANUEL: So, right now I think

we just pay, you know -- we have a shared base resource, so we pay a percent of the revenue requirement. So, is that going to be the same for this (inaudible) requirement now we just pay our base resource percent share of that?

AUTUMN WOLFE: Yes, sir. So, these charges will flow through the power revenue requirement and you will pay your base resource percent share of the power revenue requirement. Go ahead.

WILLIE MANUEL: Yeah, so the new rate schedules being proposed, they don't really directly apply to TID. It might apply to the WAPA Merchant, as you said, and then from there, it goes to the brown dots there -- the PRR, and then that's how we get it?

AUTUMN WOLFE: That's correct. That's correct. The new proposed rate schedules apply to WAPA Merchant and transmission customers subject to our tariff. Customers like TID, you're not impacted -- you're indirectly impacted by these EIM charges and benefits as things flow through from WAPA Merchant to the power revenue requirement.

WILLIE MANUEL: Do you have an idea how much of the percent of the cost sill go to the under-transmission customers and the WAPA Merchant

(inaudible)?

AUTUMN WOLFE: That's a good -- that's a very good question. More to come.

WILLIE MANUEL: Oh, okay.

AUTUMN WOLFE: No worries. In the next portion of our presentation -- not the next one, but further on in our presentation, we'll talk a little bit about the valuation of our participating in EIM. But we shared some very high-level estimates of what the ongoing costs -- administrative-type costs are, and what the potential load-based costs might look like. And then what we -- what we estimate might be received as a benefit from our participating in the market.

So, that calculation is coming up later on and that'll kind of give you an idea of what the net impact might be to the power revenue requirement.

WILLIE MANUEL: Thank you.

AUTUMN WOLFE: Sure.

TONY HENRIQUEZ: Okay, so I do have a couple of raised hands. Let's start with Ms. Lena Perkins. You are now unmuted, Lena.

LENA PERKINS: Hi there. Can you hear me?

TONY HENRIQUEZ: Yes.

LENA PERKINS: All right. I think most of my questions are going to be addressed later in the presentation so I'll let Autumn go through it. They're similar to some of Willie's. So I should have unraised my hand. And I will hold my question.

AUTUMN WOLFE: Thank you, Lena.

TONY HENRIQUEZ: Okay. And then our next question is from Ms. Regina Rieger. Go ahead, Regina.

REGINA RIEGER: Thank you. Thank you, again, Autumn. And could you refer back to slide 15? There's a list of entities that are listed there where, if I understand your presentation correctly, represents the load in WAPA's BA that is the 8.6 percent share of implementation and ongoing costs.

AUTUMN WOLFE: That is correct.

REGINA RIEGER: Okay. And of those customers there, can you identify what is conforming and nonconforming in the context of the presentation that you just shared?

AUTUMN WOLFE: Sure. So, all of the -- on slide 15, all of these customers that are within WAPA's SBA, sub-balancing authority, are conforming loads with the exception of Lawrence Livermore National Labs. They are considered a nonconforming

load. And then -- and then there are some project use customers like Shasta that are also nonconforming loads.

But as far as the non-energy loads that we see on the slide on the screen, it's only Lawrence Livermore Labs that is considered a nonconforming load. Everybody else is considered conforming.

REGINA RIEGER: Okay, thank you. And just to follow up then, so, there was a reference to direct charges from the ISO for nonconforming and charges from BANC for conforming. Is there a process in place where those load-based charges will be tracked and identified as part of the overall EIM costs?

AUTUMN WOLFE: Yes. So, very good question. So, the process for allocating those tier 1 charges that -- from conforming loads that flow through from CAISO to BANC and then from BANC to WAPA. That tier 1 allocation is actually documented in business practices. It's business practice 44 that we posted on Oasis. We had a 30-day comment period where we shared those business practices with customers. And so those have not been finalized yet but that will formally document that tier 1 allocation.

REGINA RIEGER: Thank you. No further

questions.

AUTUMN WOLFE: Thank you.

ARUN SETHI: Hi, Autumn. This is (inaudible). Just one point of clarification is that (inaudible) is a nonconforming load and (inaudible) so that includes 30 (inaudible) also as a nonconforming load.

AUTUMN WOLFE: Thank you for that clarification. Thank you, (inaudible).

TONY HENRIQUEZ: Go ahead, Koji.

KOJI KAWAMURA: Are there any other questions in the chat or raised hands? If not, let's go on ahead and open up the phone lines.

TONY HENRIQUEZ: I don't have any raised hands or chats right now. I'm going to go ahead and open up the phone lines and I'm going to start with Mr. Brian Schinstock. Do you have any questions, Brian?

BRIAN SCHINSTOCK: Am I -- yeah, I didn't raise my hand. I don't know why it keeps coming up, though.

TONY HENRIQUEZ: No, no, you were not raised hand or anything like that, just because I know you don't have the ability to unmute yourself, so we have to go through the process of unmuting the lines,

just to make sure that we understand whether or not you have any questions.

BRIAN SCHINSTOCK: Oh, gotcha. Thanks. I have no questions.

TONY HENRIQUEZ: Thank you. And then I have -- sorry, trying to -- okay, looks like phone number 916-835, and that may be Mr. Josh Blake, I think. I've unmuted you. Do you have any questions? That's phone number 916-835. Okay, no questions.

RILEY KELLY: This is Riley Kelly from the city of Roseville. No questions.

TONY HENRIQUEZ: Thank you, Riley.

KOJI KAWAMURA: All right. Sounds like there aren't any more questions, so let's go on ahead and move on to the next presentation.

AUTUMN WOLFE: Okay, thank you, Koji. So our next presenter is Dr. Tong Wu, our settlements manager here within the Sierra Nevada region. Tong?

TONG WU: Good morning. My name is Tong Wu. I'm settlement manager. Thank you for providing an overview of the charge codes. I'm going to talk about some of the details of these charge codes. There are three categories of charge codes. The first is Tier 1 and in Tier 1, we allocate charges coming from BANC to the transmission customers. One

of the transmission customers is the merchant. For the amount that is allocated to the merchant, we allocate the amount to the merchant's customers; that's called Tier 2 allocation.

And also we have CVP generators and Tracy Pump, and Lawrence Livermore load, that are modeled as generator or NGR (non-generator resources) model that's the name for modeling nonconforming load. So the WEIM, SCID will submit schedules to the ISO directly for these resources, and we also receive settlement statements from the ISO directly. And that's another resource settlement allocation. So I'm going to go through these one by one. Next slide.

Before we get into details, let me explain the term charge a little bit. The ISO uses the terminology charge and charge codes for each type of settlement for a certain amount. The ISO gives them the numerical code identifying codes, and for each amount the ISO calls it a charge. The charge can be positive or negative. Whether a charge is positive or negative, actually indicates whether it's actually a charge or a payment from the ISO. So when you see the term charge you might have a charge, it doesn't mean it's always a charge -- a cash flow from the participant to ISO. It could be the other way around.

Another brief explanation of the term is the relationship between charge, payment, cost, and benefit. Whether a charge is positive or negative, it indicates cash flow, the direction of cash flow. It is not directly related to cost or benefit. Let me give you an example. Say I have a generator that has a cost about $30 per megawatt. So it submits a bid to the ISO at $30 per megawatt. And ISO market price is lower than that $30 per megawatt, say, $20 per megawatt. As a result of that ISO says “I want to instruct your generator down a megawatt.” Say I'm operating at 100 megawatt. ISO says go to 99 megawatt.

So I reduce my output a megawatt. The EIM is an incremental market in terms of the settlement. The ISO settles the amount between the base schedule and the market instructed value or metered value. I'm going to talk about those in detail. For this particular example, ISO instructed the generator to go down a megawatt so the decremental amount is a megawatt, so in this case, the generator will get charged $20 per megawatt.

In this case, although it is a charge, it doesn't mean a cost, because the cost of the generator is $30. The generator costs $30 per

megawatt. So when the generator gets dispatched down, it is paying $20. So for that megawatt the generator is not generating if the generator has an opportunity to release water and generate in the future hour to make $30 per megawatt, actually paying $20 at this moment is a benefit.

You could consider the opportunity where the potential benefit is $10. For the same amount of water and generation that -- I'm not dispatching now, I'm saving it for future and I could potentially make $10.

TONY HENRIQUEZ: Dr. Wu?

TONG WU: Yes.

TONY HENRIQUEZ: I apologize for interrupting. I received a request, if you could speak up just a little bit more.

TONG WU: Okay. Maybe get the microphone closer to me.

TONY HENRIQUEZ: Sorry, we're -- I guess they're receiving a little bit of static on their end.

TONG WU: Okay. Is it better now?

TONY HENRIQUEZ: Yes, that's better.

TONG WU: Okay. So I just tried to clarify the term “charge.” With that out of the way,

let's talk about specific charges. I'm talking about Tier 1 allocation here. For Tier 1 allocation, there are only two charge codes. They're all related to instructed imbalance energy. One is 15-minutes market instructed imbalance energy. The other is real-time market instructed imbalance energy.

For these two charge codes, these charges, we're going to allocate these charges according to the information on the eTags because we do not submit any participating resources through BANC to the ISO, so they instructed imbalance energy would only occur on interties.

So when there are involuntary interties schedule changes after T minus 57 -- that's the time when merchant can no longer change the schedules -- so anything after T minus 57, just depends on BANC and ISO.

When that schedule changes, the change is considered instructed imbalance energy and there will be settlement for that deviation from the schedule. And we can use the information on the tag to identify which party this settlement should go to. For all the other charge codes, all the other charges, we will allocate according to metered demand. Let's say, load ratios. Next slide, please. There's a long

list of charge codes. I grouped them so it's convenient for me to present. Let's just go through these groups. Later on, I'm going to show you the whole list of charges, all of them, but now let's just go through the groups for convenience.

The first one is GMC, grid management charge. ISO as a not-profit organization, they use GMC to collect money to support their operations. That is allocated by load ratios. The second one is scheduling coordinator charge. In order to do business with ISO, you have to register a scheduling coordinator ID. In this case, BANC would have to register a SCID. For the SCID, there's a $1,000 per month charge and WAPA would get its portion of that, and then WAPA will allocate this by load ratios.

The next two, 64600, 64700, these charges were already discussed. These will be allocated according to tag information. The next one is real time uninstructed imbalance energy. We talked about instructed; now it's uninstructed, basically, that's the difference between what the load schedule is and what the meter value for the load is. That's uninstructed. After you consider instructed, uninstructed, there will be some energy that's not accounted for because different ways of loss estimate.

ISO has ISO's way of calculating loss in their system and then when we report meter data, we have another way to do that, so there are differences between the loss estimates. That becomes unaccounted for, though, and will be settled. Entire settlement is also (inaudible).

Even though we can balance all the energy, but from money point of view, after you have settled instructed, uninstructed, and accounted for, there will be some money left on the table. One source of this is called congestion offset because ISO settles energy using the so-called locational of marginal prices and the LMPs have a component -- a congestion component.

It's a value placed on congestion from one point to the other. So because of the value, if there's a congestion from a generator to the load, the load gets charged higher than the generator gets paid, so there's money left on the table. It's the congestion revenue. So that's the source of the congestion offset. And also the losses. The ISO calculates the losses through their LMPs. There's another component called the loss component. Because of that, there's marginal loss offset. After you consider congestion offset and marginal loss offset,

there will still be left over part, either positive or negative, called imbalance energy offset -- a general offset. Those would be allocated by load ratios.

Now, let's talk about capacity. We just talked about energy. Capacity: ISO has spin and non-spin services and so there are charge codes listed there for spin and non-spin services. Those charges will be allocated according to load ratios. The next group of charge codes are related to flexible ramping capacity that can ramp up and down. The ISO needs to follow load and sometimes the load changes drastically, and so for resources who can provide flexible ramping, they'll get paid. And then people who cause the steep ramping will get charged. Some of these are payments; some of these are charges, but as far as BANC charge allocation is concerned, for WAPA, we allocate these by load ratios.

The next two are related to over scheduling and under scheduling. The ISO expects all EIM participants come to the ISO with their load and generation balanced, and EIM is a market to optimally dispatch resources, but EIM is not a place to make sure load and gen are balanced to begin with. So if you don't come in balanced, there will be over scheduling and under scheduling charges.

They have an incentive mechanism as some EIM entities are balanced and some other entities not balanced. The money that they collect from people who are not balanced would be allocated to the EIM entities who are balanced. So that's the slide -- there are two charges: one is charge and the other is allocation of the collection from others.

The next group: it just lists a whole bunch of different (inaudible) things. One thing is the real time bid cost recovery. The ISO pays generator according to LMP, so there are situations when the LMP may be lower than the generator's bid.

In that case, if ISO still wants that generator, ISO would make whole for the -- to the generator, paying a bid cost recovery amount to make the generator whole. And because of that, ISO has to allocate the bid costs -- bid cost recovery cost to load. And there's also system-wide, system imbalance energy offset. That's the third category, those are allocated by load ratio. Okay, next slide.

Now, I went through these category, just to give you an overview of the type of charges. But if you want to know more about it, you can go to the table that was part of the material posted on the website. I'm not going to go through each one of

these charges in detail, but I want to go through these columns so when you read it, you understand the structure of the table.

First column is the charge code. Now, if it is a three-digit code, it's for a BANC balancing account. It has a BANC specific, not ISO, charge code, but the rest of the charge codes are the same as the ISO charge code. You can go to the ISO website, go to their business practice manual section, and you can look up the explanation for each one of the charge codes. Also BANC published their allocation manual. You can find the explanation for each one of these charge codes.

So the second column is basically -- a name for that code. The third column is called BANC allocation basis. This is how BANC would allocate these charge codes. The next column is called WAPA Tier-1 allocation. That's how WAPA would allocate each of these charges to its transmission customers, including WAPA merchant. And then the next two columns are allocations for "TPUD to BANC" and "Others". Those two columns represent the Tier 2 allocation within WAPA merchant as one of the transmission customers. TPUD is one of the largest load in the sub-BA and because of agreements between

TPUD and another BANC participants, their settlement is separate than the rest of the conforming load. The rest of conforming load charges are allocated to PRR.

I'm going to talk about these in greater detail in my later presentation. At this point, I just want to point out these are columns, what they are. And then the second column from the right is labeled as “Allocation Granularity,” based on which we say load ratio is by daily load ratio, monthly or hourly. There you can find that.

The last column indicates which rate schedule would apply and Autumn will talk about these rate schedules after my presentation. Okay. Next slide.

COURT REPORTER: Hello? Hello, this is the court reporter. Excuse me. I can't -- I lost Mr. Wu. I cannot hear him. When he said, "Next slide," and I guess he went to slide 42.

TONY HENRIQUEZ: Yeah, hey, Tong. Can you go that last -- you were muted or something or we lost you there.

TONG WU: Well, that last -- yeah, the previous slide was the table that has all the details of each charge code coming from BANC. And I was

explaining the columns of that table. I don't know where I got lost, but the last column was the applicable rate schedule for each one of those charge codes. The second column from the last, that column describes the granularity of load ratio allocation because for majority of these charges, we're going to use load ratio to allocate them.

And for load ratios, some of the load ratios are hourly, some are daily, some are monthly. And so that column describes the granularity. I don't know where my audio signal got lost or if I need to repeat the whole slide.

TONY HENRIQUEZ: No, that's good, Tong. That's good.

TONG WU: Okay. All right. So we just went over Tier 1 allocation. That's the allocation from WAPA to the transmission customer. So now we're going to move to Tier 2. Tier 2 is about allocation from WAPA merchants to its customers, basically its load customers. So for Tier 2 allocation, again, first we're going to identify those tags that have to do with the Instructed Imbalance Energy deviation – IIE, and after that, we're going to allocate all other charge codes by load ratio.

First, we would allocate charge codes

according to load ratio for TPUD and the rest would go to PRR. Now, so BANC needs to take care of TPUD -- take care of the amounts allocated to TPUD. We simplified the process; instead of receiving numbers and do the calculations and send numbers back to them, BANC graciously agreed to do that calculation, to minimize the back and forth transfer of numbers, which simplified IT development. So actually, BANC will calculate the TPUD portion.

Okay, next slide. There are a few charge codes WAPA will take care of for TPUD and these are the instructed deviation and uninstructed deviation. Since TPUD does not have intertie transaction directly, the instructed imbalance energy charge codes 64600, 64700 do not apply directly. Only the first one, the 64750, applies. That charge code represents uninstructed imbalance energy in EIM settlement. That charge code has to do with the difference between scheduled energy and the metered energy.

So when we forecast TPUDs load, we meet the load with CVP hydro. Once we go EIM, the ISO will forecast the total and we forecast TPUDs load schedule. And then at the end of day, the meter quantify will be different from the load schedule.

WAPA will take care of that difference because TPUD is a first preference customer. TPUD is in WAPA's sub-BA. We take care of TPUD.

For other first preference customers, when they have uninstructed balance charge today, the ISO charges us. We do not pass those charges to the first preference customers in the ISO. So the treatment here for TPUD is consistent with how we treat other first preference customers in the ISO. Because they are first preference customers, we're supposed to meet their load.

When our forecast is different from the actual today for TPUD, we will just use our CVP generation or we will make purchase for the control area, and a part of that purchase would go to TPUD. But today, we need to balance physically, but after joining EIM, the ISO will dispatch generation to meet that imbalance, or, a portion of that. If ISO dispatch generators either in or outside sub-BA to meet TPUD's load in real time, we will pay for that.

And again, here, the charge -- this charge, 64750, could be positive or negative, as I indicated earlier. If the forecast is higher than the meter, actually that charge will be negative. That means ISO will pay us for that. But if we under

schedule and the metered load number is higher than the forecast, then the ISO will charge us. And so it doesn't matter whether it is positive or negative, that amount will go to PRR.

For all the rest of the charges, they would go to BANC. BANC members would either pay -- again those amounts that go to BANC, can either be positive or negative, or be paid the amounts. Okay, next slide.

This is how BANC will do that. Every day, BANC would calculate TPUD allocations for each charge sent to WAPA and determine whether that amount is for WAPA or TPUD. And on a monthly basis for that portion that is allocated to WAPA, excluding TPUD, WAPA will get invoiced. For the TPUD portion, BANC will get the invoice and BANC will track TPUD's portion of the charges. Next slide.

Okay. Now, I'm going to switch gear to talk about WEIM. To talk about the CVP generators and the two nonconforming load that we submit to the ISO directly and receive settlement statements from the ISO directly. The three generators Shasta-Trinity, New Melones and Folsom-Nimbus. These are generator aggregations, and then Tracy Pump. They're all WAPA's resources, CVP generation and Tracy Pump (inaudible).

There is another load, Lawrence Livermore load. That load has supercomputer load and the whole Lawrence Livermore load is considered a nonconforming load. ISO has difficulty forecasting nonconforming load.

And so we will forecast and schedule the load with the ISO as a NGR. NGR is a model used by the ISO to schedule nonconforming load. That's one of the purpose of the NGR model. For NGR, for these two resources, Tracy Pump and LLNL, we do not submit a bid. We just submit a base schedule and they will not be dispatched and they'll be treated as load. All right. Next slide.

Okay. For each of the charge codes, they will be obligated to one of these categories. Let's go counterclockwise, starting with LLNL NGR. The charge code based on -- will be based on certain criteria: the resource ID or either load or meter gen or just direct pass-through to PRR. So for each one of the charge code, it will have -- it will go to one of these buckets. LLNL, Tracy Pump, Trinity aggregation, Folsom aggregation (inaudible). And some charge codes cannot be allocated easily, and also it -- part of it, it's not proper to do the allocations. For simplicity, those charges will be passed to WAPA merchant and to PRR at reckoning. For all these

buckets except the LLNL, they will all go to PRR, because either they are CVP generation or project (inaudible). For LLNL, for the portion that is allocated to LLNL, it will be billed to the Lawrence Livermore lab. Next slide.

Now, let's go to -- let's go over details how each charge is allocated to one of those buckets. The first method is by resource ID. Each one of these resources, whether they're generation or NGR, has a unique resource ID. For instructed and uninstructed deviation, they can be easily allocated based on the resource ID. And for the SCID charge, and we already -- we mentioned that for the SCID there's a monthly $1,000 charge. We will divide that by five because there are five resources. Each resource will get $200. LLNL will get $200 and the rest of $800 will go to the other resources, and then eventually end up in PRR. And then some charge codes are allocated by meter ratio share and here, when we say meter ratio share, we mean absolute value of the metered quantities. We don't use positive sign for gen and negative sign for load. They're all positive. We make them all positive. Just straight meter ratio. These meter ratios are calculated on hourly, daily, and monthly basis according to the particular charge.

We'll go through that.

And the rest of the charges, just go through WAPA merchant and pass through PRR. We'll go through the details. Next. These are the three charges. The instructed and uninstructed will pass these charges by resource ID.

These are the charges that we will allocate based on meter ratio share. Let me go through these briefly. First of all, enforcement protocol. So when somebody submit their meter data late or some other (inaudible) some other ISO protocols, the ISO will charge that entity. Once that entity pays the ISO, the ISO would allocate that to the rest of the market in principal, to people who pay GMC. So that amount, the payment, will be allocated based on meter ratio monthly.

GMC. That's ISO's grid management charge. ISO collects GMC from the market. That will be allocated according to our rate meter ratio. The next four charges are related to flexible ramping. These would be allocated according to meter ratio based on the granularity of that charge code. The ISO allocated that data. We allocate data. ISO allocate that. Allocates that monthly. We use monthly meter ratio. Those are the -- one of them.

The next two 7989, 7999, those are related to interest. The ISO use a incremental settlement method, meaning that they settle three days after market is settled, 12 days after the market, using estimated meter data and then they settle again 55 days after the market when the real meter comes in. So they want to settle as soon as possible, so to make sure that market participant receive money or pay bill quickly. But then, the true up, as they go through the next billing cycle.

But between these billing cycles, they calculate the interest, so they charge interest or they pay interest, depending on how your meter data, where it's above or below the estimates.

And so there are two. One is they charge the interest. The other is they pay the interest. Those will be allocated based on meter ratio data. Generators and their connection process allocation, some generator loss to the grid and ISO requires a deposit, and then the process that we go through, the amount is forfeited by the ISO, then the ISO (inaudible) that amount to the market based on who pays GMC. That's the last one. These are the charges that we'll be able to give by meter result here. Next slide.

These charges will be passed to WAPA PRR directly. Some of them is because they share; some of them just for convenience. Let's go through them.

Default interest payment. Sometimes, the defaults, they owe interest to the ISO, so they pay ISO interest, ISO allocates that to the market. That's the default interest charge. If WAPA defaults, WAPA will pay ISO interest and WAPA will not default, but those two are linked together. They just go to PRR.

GMC transactions fee. ISO charges a small amount for every segment of the bid, the energy bid. You can have many segments. Say, $20 per megawatt up to this amount, and above that, I want $30. There's bid curve for each one of the segment ISO charges. Actual CVP will participate in EIM, so CVP will submit by sensitive bids, the load will not. LLNL cannot. The Lawrence Livermore load will not even submit any bid at all. So therefore, this one goes to PRR directly. Invoice and BANC payment penalty. If WAPA is late on paying the bill, there are several times (inaudible) late or payment (inaudible), WAPA never got into that situation but if we do, that will go to PRR.

Financial security posting collateral. If we need to post collateral, like a federal government, we cannot post monetary collateral, but if we do stand -- if we were late on payment, that's the charge. So that will keep (inaudible).

Flexible ranking forecast movement settlement and the next two. 7071 and 7081, these two are -- have to do with a resource. It is a payment to the resources who provide flexible ranking. Only CVP generation can provide flexible ranking and Tracy Pump and LLNL looks not, so therefore, it doesn't make sense to allocate to the load, so these two will go to PRR because, yes, we were allocating these two CVP generators, we will go into PRR anyway. 7070 is related to these payments as well. It's an adjustment, so all these three go to PRR directly.

Bid cost recovery settlement. So if CVP (inaudible) bid a certain amount, say $30 and then the LMP is lower than $30, the ISO would pay bid cost recovery payment to CVP generation and this is -- the load cannot -- the load will not bid in the ISO market, so the bid cost recovery doesn't have much to do with the loads, so this charge, they allocate to PRR directly for simplicity. So that's the allocation methods and so it's direct pass through to PRR for

these charge codes. Next.

I think this is the last one. Yeah. That concludes my presentation. Let's go to any questions.

KOJI KAWAMURA: Thank you, Tong, for your presentation. Tony -- I don't see any questions in the chat. Do you have any -- do you see any raised hands?

TONY HENRIQUEZ: So I do have a question that was sent directly to me. It looks like it's from Bill Hughes and I'm going to go ahead and unmute Bill. Go ahead, Bill. BILL HUGHES: Hi. I do have a question. Just wanted to point out that there was a discrepancy on these slides. slide 40 said charge code 4575, which is the SCID fee that's been allocated, the above ratio share and then slide 47 showed it as being a simple division by five. So I just wanted to point out that there was a discrepancy there.

TONG WU: 4575 SCID charge. Where is the discrepancy? On which page? BILL HUGHES: Well, you can see on this one, the current page, it says $1,000 divided by five, but --

TONG WU: Yeah.

BILL HUGHES: -- slide 40 --

TONG WU: Okay. BILL HUGHES: -- share.

TONG WU: Let's go to 40.

BILL HUGHES: (inaudible).

TONG WU: Yeah. Because -- yeah. That's very good question. That helps to clarify things. This is a Tier 1, so here, what we use, load ratio, we're allocating the amount coming from BANC to our transmission customers and then they actually go to (inaudible) customer. This is a charge coming from ISO through the BANC EIM entity, but the other one, later on I think it's Page 47, for the settling charge problem, that is allocation for the so-called participating resource SCID to this participating resources.

This amount comes from the ISO directly for the SCID (inaudible) EIM. This is not the BANC's SCID. So we're using different methodology here to allocate BANC's charge, the load versus the same charge code coming from the ISO to the resources.

BILL HUGHES: Okay. Yes, I understand now. Thank you.

TONG WU: Okay.

TONY HENRIQUEZ: Okay, thank you about that. Looks like I have a question from Ms. Regina

Rieger. I'm going to go ahead and unmute you. Go ahead, Regina.

REGINA RIEGER: Tong, thank you for your detailed presentation. It was helpful. I did have a question. On slide 39, you were referencing changes at the intertie after T 57 and the implications. Does that relate also to changes at Tracy Pumps and if so, do you have a sense of how often that might happen?

TONG WU: Yeah. For change -- okay, for instructed imbalanced energy, coming from BANC as the EIM entity, those would occur on interties only, because we do not have any participating or nonparticipating resources to rule BANC's EIM entity. Only conforming mode are submitted to ISO using EIM entity as the SCID. So only the instructed imbalance on intertie applies, so those would go with the e-tag. That has to do with T minus 57. As far as Tracy Pump is concerned, Tracy Pump is not a schedule on intertie. It is a NCR that is scheduled as a special load through the ISO. If that load deviates from its schedule, it is not going to be instructed. It's going to be uninstructed. It would be the -- the difference would be between its schedule and (inaudible). That would be considered unscheduled

deviation. That is one of the three charge codes I listed there, but it is not going to be the same as the instructed.

Your question is still valid. Would Tracy Pumps schedule be different its meter mode, to what extent there would be different from its meter load, regardless what charge code would apply. But that question, I don't know. We'll have to see.

REGINA RIEGER: Thank you. That's -- I appreciate the clarification and that would be good information to know, given the volume of those pumps related to the conforming load as a ratio. One other question, if I may. Sorry about that. On slide 41, I believe, the first three charge codes listed there, 100, 101, and 102 have no applicable rate schedule. Can you clarify how those costs are allocated?

TONG WU: Yeah --

REGINA RIEGER: What -- is it, under what rule?

TONG WU: Right. For us, they will be allocated based on the load ratio. If you look at one, column enter WAPA first tier allocation and also second tier allocation, if you (inaudible) to BANC, those are all those ratios. So for us, we just allocate those by load ratios. But in terms of the

rate schedule, applicable load rate schedule, I think maybe Autumn will present that later on, regarding which rate schedule would apply.

These are specific charge coming from BANC, not from an ISO. For example, the first one, BANC balance in the account. BANC will calculate -- try to allocate each one of those charges to either the fifth decimal or something. They try to allocate it as accurate as is possible, but because of the numerical errors at the end of the day, there might be some residual. I don't expect accuracy to the fifth dig, but that would go to 100.

There are some BANC pass through billing charges, let's all it pass through billing charge. Those are pass through case by case basis. BANC does not have six -- like, depending on what's the nature of that pass through. One or two, BANC miscellaneous charge. That's just a miscellaneous, a lot of things that it doesn't occur routinely or a small amount. I don't know whether that answers your question. Those are kind of catch-all kind of charge codes, used by BANC to take care of things that might not have been explicitly specified.

REGINA RIEGER: Thank you, Tong. I guess what I was looking for, and maybe I should ask

this more clearly, if it's not a reschedule, is it pursuant to a business process?

TONG WU: As far as a business process is concerned, there is business process manual, BP-044, and there is this table so the methodology for allocating these charges are clear, explicit. They're done by load ratio (inaudible).

REGINA RIEGER: Okay, thank you.

TONG WU: Yeah.

REGINA RIEGER: No further questions. Thank you.

TONG WU: Okay.

TONY HENRIQUEZ: Thank you, Regina. Thank you, Dr. Wu. So I'm checking for any raised hands and I don't see any and I don't have any other texts in my inbox, in my chat box.

KOJI KAWAMURA: Yeah, why don't you open up the lines next. Yeah.

TONY HENRIQUEZ: Okay. So I'm unmuting Riley Kelly. Riley, do you have any questions?

RILEY KELLY: No. No questions on my end. Thank you.

TONY HENRIQUEZ: Thank you. And that is the only line that I have right now, Koji.

KOJI KAWAMURA: All right, thank you,

Tony. So let's -- if there are no more questions, let's go on ahead and move to the next presenter.

AUTUMN WOLFE: Okay, so Robert Delizo, our resources and scheduling manager will share a little bit of information on EIM resource valuation. This is where we get into the benefits that we may realize for participating in the EIM market. Robert?

ROBERT DELIZO: All right, good morning. Can you hear me?

TONY HENRIQUEZ: Yes, we can hear you, Robert.

AUTUMN WOLFE: Thank you.

ROBERT DELIZO: Thank you. All right. So thank you for taking the time to participate in today's rates public information and comment forum in order to understand WAPA's plans for EIM participation, originally started our schedule to start in April 2021, and as you've heard, that date has been moved up to March 25, 2021.

So this presentation will focus on the calculation of potential EIM dispatch benefits for using Central Valley Project and strategies for participating or getting into the types of energy (inaudible) market.

So in this slide, the following are

the assumptions used in the valuations. The calculations are a refresh of what we presented last year to the customers and also we presented this in the June 8 informational customer meeting as well.

We assume reserve capacity that was available for marketable research offers, but it dropped to resource and we got the capacity to 60 megawatts where the capacity is higher than 50. Otherwise, we use the actual volume. And for EIM dispatch, we assume there's a plus or minus of 50 megawatts flexibility from the basis schedules that is (inaudible) that dispatch about 50 megawatts, if 50 megawatts is available. Otherwise, that's limited to the actual marketable reserves that were available in our schedule.

We applied a 200-megawatt cumulative generated energy or purchased energy as a constraint in either direction. This means that if the resource is continuously being (inaudible), we cap that to 200 megawatts, then assume that the bidding is put on hold until the resource receives that dispatch.

So at the end of the day, the resource can potentially be a net positive or negative energy position. This means that we have either generated too much or purchased too much compared to the

scheduled generation for the day. So 600-megawatt cap for the week is applied similarly to the 300-megawatt cap. For that adverse impact to the daily schedule of CVP generation for its normal use or allocation to have purchased for project use, first preference energy, the needs for the SBA and also for rates resource.

And we also assume that the load matches the EIM resource schedule such that I think at that dispatch is either sale or purchase opportunities, respectively. Next slide.

So this slide shows an illustrated example of balancing supply and demand in the SBA or sub-balancing authority area, other EIM. So resources are comprised of generation and imports while demand is comprised of (inaudible) load, (inaudible) model that NGRs, and exports.

Imports and exports here are from the WAPA and SBA perspective, meaning imports are energy transactions that originate from outside the SBA and sync in the SBA, while exports are energy transactions originating from the SBA and sync outside of the SBA. NGR here stands for non-generator resource. As mentioned earlier, this model is used for nonconforming loads, in particular Tracy Pump load

and the Lawrence Livermore Nation Lab load. What that means is WAPA and USBR are able to forecast that load better than the ISO, so those loads are essentially not part of the boundaries for CAISO's load forecast under EIM.

So WAPA's NGRs are model of generation type resources with generate -- with negative generation and all the update schedules and no (inaudible) bids, as mentioned earlier, and they will be considered as self-scheduled resources, so from EIM generation based schedule point of view, the NGRs are loads that served by the generators, as you can see on the right side.

In total, WAPA's EIM generation is comprised of all the USBR's generation facilities that are situated or consider situated in the SBA, just like (inaudible). These allocated resources are based to date on geographical location that line up with reservoir and river flow management requirements and transmission paths that are considered in our scheduling. All right, so next slide. This shows that WAPA is the next order of CVP energy.

These export schedules are part of the basis schedules of WAPA under EIM. So depending on the price between LMP and the bid price, we foresee

taking lower priced energy to serve our SBA load or selling energy outside of the SBA. This portrays our sales -- our decremental or incremental dispatches of the EIM generator resources as shown here in the examples you have (inaudible), indicating certain EIM resources going down or going up.

All right, so next slide. Ideally, you have the net energy generated and purchased in the day should be zero. That would indicate that reclamation is water neutral for the day. The goals of the EIM dispatches are to achieve high value sales from incremental dispatches to the day's schedules and lower price purchases from decremental dispatch to the day's schedules.

In our simulation, we ran four cases to show that all of these prices are indicated for each phase. Phase one here is a scenario where we intend to bid at cost for all hours. In this case, we are willing to sell energy for higher and purchase energy for lower than our cost. Phase two is a case where we perceive a need to generate, are probably willing to do so if the price is not negative. And phase three and four are attempts to simulate managing the reservoir levels.

The bid prices are intended to realize

opportunities for using EIM dispatches to manage the reservoir levels. So note that the simulation used the static bids and basically, you can consider it being on a qualified mode and I'll show more to that later. There is no selective placement of bids or inter-hour merchant adjustments of the bids to optimize sale and purchase dispatch.

Next slide. All right. So this chart shows the interplay of the 15-minute market prices and the real time dispatch for (inaudible) prices and the resulting FMM award and RTD dispatches. So the two lines that are tracking together of olive and red lines are the FMM and RTD LMPs.

When the FMM LMP is higher than the bid price indicated here by the gray dotted lines, the resource has an inc award and when the FMM LMP is lower than the bid price, it reduces that award.

So the FMM award is shown by the green line which gives us the secondary axis on the right, the values of plus 1 or minus 1, meaning inc or dec. The five-minute dispatches are shown by the blue dots, which are also using the secondary access and are incremental or decremental to the FMM award.

So the chart on top shows the dispatches based on the price, while the chart at the

bottom shows the application of the 300-megawatt cap that we put to kind of manage the dispatch. You can see here the green, hours 16 and 19, the decremental dispatches are suppressed due to discount. And this slide in particular shows a phase three scenario. You can see the bid price around $15, which is half of the cost that we have indicated previously.

All right, next slide. And this is similar to the previous one, except that it is for a phase four scenario. Due to the higher bid price in the latter half of the day compared to phase three, there are a number of FMM (inaudible) after hour ending 19 where the FMM price is lower and that resulted in dec awards. In the next slide, I'll go -- I'll show relative volumes of inc and dec dispatches as well as the extent of the cumulative daily net generation. So let's go to the next slide.

This slide is only for the period of January to May this year. Like I said, shows the relative volume of purchased and sold energy on a daily basis. The gold bars represent sales and the light green bars represent the purchases. And the dashed lines at the bottom indicated the net position for each day, so you can see here, it's mostly dates showing net purchases.

And as we mentioned previously, to continue with accrual in one direction will not be sustainable for reclamation at the managed reservoir levels, which is why we put that 600-megawatt cap, and I'll show that again in the next slide.

So let's go to the next slide. So like I said, the simulation is pretty much on autopilot mode, which is why it would make that 600-megawatt hour cap for each week so that we could manage the amount of cumulative dispatches to that reclamation will be able to manage the reservoir levels with that constraint, basically (inaudible).

Like I mentioned earlier, the simulation gives the static bids and what pretty much on autopilot mode. That controls basically the breadth of the dispatch and once the caps are met, and that is shown by the periodic no-purchase, no-sale days in the week, as you can see here in this chart.

All right, so let's go to the next slide. Regarding the results of the simulations, so the table on top shows the some of the daily imported or purchased energy from the market and also some of the daily exported or sold energy to the market. The table at the bottom shows the counts of the days with imports or purchases and exports or sales. Also

indicated are the counts of days with the net imports and days with net exports.

All right. So that's for that slide. Let's go to the next slide. Next slide, please. So this shows a summary of the EIM -- let's go back to the previous one. This shows the summary of the EIM dispatch benefit. The purchase benefits represent cost savings. For example, the FMM that dispatch will result in cost savings of the difference between the break-in cost and the FMM LMP. I think Dr. Wu alluded to this activation earlier.

The savings that we get is basically the difference of those two prices. These numbers are a result of interplay available capacity of the bid prices, LMPs, as well as the caps that we put in place. The total EIM dispatch benefit is the sum of both the sale benefit and purchase benefit. Next slide. So as we mentioned earlier, we use the spinning reserve capacity as a proxy for EIM resource capacity, and this slide is intended to provide kind of (inaudible) of the cost and only for illustrative purposes only to show a more accurate depiction of the benefits for the alternative use of the capacity. The EIM dispatch benefit is reduced by the spinning reserve revenues that we would have realized if that

capacity was sold in that market. So these calculations assume that WAPA participated in EIM since January 2017.

All right, so let's go to the next slide. The previous slide showed kind of a run of the simulation that's pretty much a continuous basis, meaning like I said earlier, if we were in the market for EIM since January 2017, then we would have tracked that set of numbers. This slide, though, is a version of that simulation where we use historical average numbers. In a way, it's a calculation for potential future values. This applied to average spinning reserve capacities as well as average FMM, RTD, and the spinning reserve market clearing prices.

Again, spinning reserve capacity gives us proxy resource for EIM resource capacity that this slide is intended to provide illustrative numbers only. So these calculations are projected net EIM dispatch benefits. Okay, so let's go to the next slide. We put this slide together to compare the dispatch benefits with the estimated ongoing EIM cost and estimated load-based costs. This is for the purposed of coming up with a rough estimate of potential future net EIM benefits.

Please note that the load-based costs

may fluctuate as they are a function of market prices. This shows that there could be net EIM benefits that will be applied to PRR. As I mentioned earlier, the dispatch benefits, the numbers are based on the interplay of the capacity, the bid prices, LMP caps; hence, they may not be representative of future EIM dispatch benefits. So WAPA basically cannot determine with certainty the quantitative EIM dispatch benefit until we are already a participating EIM.

So this concludes the presentation on EIM resource valuations. I'd be happy to answer questions about the foregoing at this time.

KOJI KAWAMURA: Thank you, Robert. I do not see any questions in the chat. Tony, do you see raised hands?

TONY HENRIQUEZ: So I do not see any raised hands at this time or questions. Never mind, I do have a question from Mr. Willie Manuel. Mr. Manuel, I am unmuting you right now. go ahead.

WILLIE MANUEL: Thank you. Thanks, Robert, for the presentation. I just have one question. So did the simulations take into account the limitations of hydro in terms of managing river flows and reservoir levels, you know, or are they just not take that in account?

ROBERT DELIZO: All right, thank you, Willie, for the question. We tried to capture that by applying the caps that we mentioned, the 200-megawatt hour cap for the day. Also, we got -- we'll kind of manage the continuous approval in one direction, and therefore might be detrimental to the water management needs, so we tried to limit the dispatches that they accumulate and cap that to 200 megawatts for the day and then wait until we get an opposing or reverse direction dispatch.

If that didn't happen for the day, we try to manage that with the application of the 600-megawatt hour cap for the week, basically, make sure that, you know, we got through the day net position.

We shouldn't go past 5600 megawatts in the week. So that's kind of the control that we put in place to reflect the (inaudible) you're alluding to.

WILLIE MANUEL: So those are reflected in these cases, one, two, three, and four?

ROBERT DELIZO: Correct.

WILLIE MANUEL: Yeah. Okay, thank you.

ROBERT DELIZO: You're welcome.

TONY HENRIQUEZ: Okay, this is Tony. I have no questions on chat and I don't see any raised

hands. I'm going to go ahead and unmute our one phone person, and I apologize for that. It's just I don't think we have the ability to unmute yourself or give me indication that you have a question, so I have to check with you. Riley, do you have any questions?

RILEY KELLY: No. No question.

TONY HENRIQUEZ: Okay. Thank you.

KOJI KAWAMURA: All right, seeing there are no more questions, let's go ahead and move on to the next presenter.

AUTUMN WOLFE: All right, thank you, Koji. Okay. For this portion of the presentation, I will share some more information on the new proposed EIM rate schedules. Next slide, please. As I mentioned earlier in the presentation, there are new proposed rate schedules for EIM. The proposed EIM rate schedules are an EIM administrative -- rate schedule for EIM administrative charges.

We have a new proposed schedule for EIM energy imbalance service and a new proposed rate schedule for EIM generator imbalance service. We also have proposed revisions to existing rate schedules for energy imbalance service and generator imbalance service. And then we have a proposed rate schedule for the sale of surplus products. We have the

website shown on the screen on this particular slide that, this is actually where you can go to find all of our rate schedules in their complete form. It was a lot of information to attach to the appointment, so we thought it would be better to just provide the website. You can find all the rate schedules, the proposed and revised rate schedules, at that link.

Next slide, please. We'd like to start by sharing the structure of our formula rates. We have three components to all of our rates. Component one is actually different for each of our rate schedules. It describes the formula rate or the penalty. Then there's component two, which is basically (inaudible) to pass through regulatory charges or credits to relevant customers. And this is standard language that's included in all of our rate schedules.

So component two is the same in every rate schedule we have posted. And then we have component three which, similar to component two, is a pass through of charges, except this one is for the pass-through charges for balance authorities, and this is the pass through -- this is for the pass through of charges or credits. And again, this is standard language in all of our rate schedules.

Next slide, please. So before I get into the details for component one of each of the new proposed EIM rate schedules, I'd like to go over the standard language for components two and three that I mentioned apply to all of our rate schedules. So this one actually shows the standard language for component two.

I won't read through it because it is rather long, but it basically states that we will pass through to our customers regulatory charges or credits for FERC, and FERC stands for the Federal Energy Regulation Commission, and then other charges that might be incurred from other regulatory bodies. Next slide, please.

This slide shows the standard language for component three, and basically what this component is showing is that we will pass through to our customers balance authority charges or credits that are applied to WAPA, so that's what this component represents. And again, components two and three are the same in all of our rate schedules that we have posted. Next slide, please.

Now we get into the specific information for component one of our new proposed EIM rate schedules. Here, we talk about the formula rate

for administrative charges. This is rate schedule CV-EIM1S. So for component one, "The EIM administrative service charge shall be sub-allocated to WAPA's transmission customers based on load ratio share for the time period in which WAPA incurs EIM administrative costs."

This schedule is specific only to CAISO administrative charges. The BANC administrative charges will flow through the power revenue requirement, as described at the beginning of the presentation. So I just want to clarify that a WAPA transmission customer would only be allocated CAISO administrative costs if they are subject to our tariff and if they have load within our sub-balancing authority. Next slide, please.

Here, we share the proposed language for component one for energy imbalance service, this is rate schedule CV-EIM4S. For component one, "EI service is the deviation of the transmission customer's metered load compared to the load component of the base schedule settled as uninstructed imbalanced energy for the period of the deviation of the applicable load aggregation point price where the load is located.

"Unless such charges are allocated to

the transmission customer directly by the Balancing Authority of Northern California as the EIM entity, a transmission customer shall be responsible for any pass through charges or credits associated with applicable EI service charges allocated to WAPA as the transmission provider for its participation in the EIM in accordance with this rate schedule. WAPA will sub -- allocate load charges based on a transmission customers' load ratio share."

Next slide, please. On this slide, we talk about component one for generator imbalance service. This is rate schedule CV-EIM9S. Component one states, "Unless such charges are allocated to the transmission customer directly by BANC as the EIM entity, a transmission customer shall be responsible for any pass-through charges or credits associated with applicable GI service charges allocated to WAPA as transmission provider for its participation in EIM in accordance with its rate schedule. "Such charges may include those due to operational adjustments of any affected interchange. WAPA will direct assign charges and/or sub-allocate charges based on the transmission customer's load ratio share." Next slide, please.

On this slide, we share specific

information regarding supplemental transmission charges while participating in EIM. Since FERC requires that entities participating in EIM already have transmission, there are no incremental transmission charges assessed for when participating in EIM.

We have specific language in our tariff that states "unless subsequently imposed by CAISO as the market operator, as part of the market operator tariff and promulgated by WAPA through rate proceedings, there shall be no incremental transmission charge assessed for transmission use related to the energy imbalance market. Transmission customers must have transmission service rights as set forth in attachment S of WAPA's tariff. We just wanted to be clear on this piece that there will be no incremental transmission charges for participating in EIM. Next slide, please. Okay. We're just on pause here. There we go. Thank you, Tony.

Okay, so this table is a quick reference guide to show the formula for each of the new proposed EIM rate schedules and the different type of charges that will settle each of the new proposed rate schedules.

So in this first row we have schedule

CV-EIM1S and this is for administrative charges. The formula for allocating administrative charges is based on load ratio share and the type of charges that would settle to this new proposed rate schedule would be administrative service charges from CAISO.

In the next row, we have schedule CV-EIM9S, generator imbalance service, and the formula for allocating generator imbalance service charges, either they will be direct assigned or sub-allocated based on load ratio share. We don't anticipate having very many charges associated with generator imbalance, but should they ever occur, depending on the type of charge, that would dictate whether it's a direct assigned charge or a charge that would be allocated based on load ratio share.

So a type of charge that might settle to Schedule 9S would be an instructed imbalanced energy type of charge. Then in the last row we have schedule CV-EIM4S for energy imbalance service and for energy imbalance service charges, they will be sub-allocated based on load ratio share. The different type of charges you might see that would settle to Schedule 4S would be charges like uninstructed imbalance energy, unaccounted for energy, under and over scheduling load, uplifts and offsets, bid cost

recovery, flexible ramping product, operating reserves.

Next slide, please. Okay, so we saw this EIM entity's settlement allocation summary total at -- think it was part of Tong's presentation and we just wanted to call your attention to it again as a good reference for quickly identifying which EIM charges were settled to which of the new proposed rate schedules. We have highlighted on the far right the (inaudible) of the different charges to the specific rate schedules that the charges will settle to and I'd like to take this opportunity to address the first three rows.

There was a question previously asked about why we have N/A identified as the rate schedule for those -- for three charge codes, and this is because those charges are specific to WAPA loads for EIM participation and they're not applicable to transmission customers under our tariff. The BANC EIM charges are proposed to be allocated to customers through the power revenue requirement and not to transmission customers. So I think we were just trying to capture all-inclusive different charge codes and so that's why they were added to the table. We probably should've, instead of putting N/A, we

probably should've put PRR in that column there. So again, these are charges that would be allocated to our power revenue requirement, because they are specific to WAPA's generation and load for participating in EIM. Next slide, please.

Okay, so on this slide, we wanted to show an example of how charges, EIM charges, would flow through from CAISO all the way through the Tier 1 and Tier 2 allocation to the power revenue requirement. So in this example, we are using GMC administrative type charges that would flow through from CAISO. They would flow through BANC and then they would be allocated based on the EIM participating entities that net energy load.

So WAPA as a transmission provider would receive a share of those GMC charges. Our share is 24.1 percent, as we described earlier in the presentation. And those EIM -- I'm sorry, those GMC type charges would be allocated to WAPA merchant as a transmission customer under our tariff and to other transmission customers that are subject to our tariff, and they would be allocated using the proposed rate schedule for administrative services which is rate schedule CV-EIM1S.

So that's the Tier 1 allocation. Then,

for those charges that are allocated to WAPA merchant, the charges are then sub-allocated, through the Tier 2 allocation to the power revenue requirement. Like I mentioned before, these are administrative costs that are -- that were described in the very beginning of the presentation and these are the costs that are going to flow through to the power revenue requirement. And then the power revenue requirement is -- of course, paid by first preference customers and base resource customers. Next slide.

And similar to the previous example, on this slide, we are showing an allocation of energy imbalance charges. In this particular example, we are showing the allocation of uninstructed imbalanced energy charges. They would flow through from CAISO to BANC and then BANC would allocate the charges between WAPA and the transmission provider and the other participating EIM entities, and that would be based on our net energy load percent. Again, we would have the -- for the charges that are allocated to WAPA as the transmission provider, they would be further allocated to WAPA merchant and other transmission customers under WAPA's tariff. And again, this is where those new proposed EIM rate schedules some in. Specific

for this uninstructed imbalanced energy charge, we would use rate schedule CV-EIM4S for energy imbalance service.

For those charges that are allocated to WAPA merchant, they will then be sub-allocated as a Tier 2 allocation to the power revenue requirement. So this kind of gives you an example of how we see those charges flowing through from CAISO all the way through to the power revenue requirement. We thought that might be a helpful illustration to share. Next slide, please.

In addition to the new EIM rate schedules, we also have revisions to existing rate schedules. As I previously shared, we have the new EIM rate schedules for energy imbalance -- that's CV-EIM4S -- and for generator imbalance and that's schedule CV-EIM9S. And this is to recover those related costs that are incurred during EIM participation. WAPA will also need to retain our existing energy imbalance and generation imbalance rate schedules to allow for cost recovery of services that we provide outside of EIM, should EIM ever be suspended. The existing EI and GI rate schedules currently allow for energy imbalance and generator imbalance settlement through energy that is returned

in kind.

WAPA's proposing to revise the existing rate schedules to require financial settlement, so the revised proposed rate schedules will be referenced as CV-EID5 and CV-GID2. Next slide, please.

For the existing energy imbalance schedule, we are proposing revisions to settle deviations within BANC financially; whereas, before, we settled with in-kind energy rather than financially. So the existing component one for energy imbalance service states that there will be no financial settlement deviations within our bandwidth and allows for energy to be returned in kind.

So the proposed revision, we propose to settle deviations within our bandwidth financially at the greater of the California Independent System Operator market price or WAPA's actual cost. Next slide.

Similar to the revisions that were made to the energy imbalance rate schedule, we are proposing to revise our existing generator imbalance schedule to also settle financially rather than with in-kind energy. So very similar to the previous slide. The existing component one for generator imbalance service states that there will be no

financial settlements of deviations within the bandwidth and it allows for energy to be returned in kind.

The proposed revised component one, we propose to settle deviations within our bandwidth financially at the greater of CAISO's market price or WAPA's actual cost. Next slide, please.

Okay, this takes us to the end of this portion of the presentation on the new proposed rate schedules. Before we turn it over to the next presenter, I'll check in with Koji to see if there are any questions on this portion of the presentation.

KOJI KAWAMURA: Thank you, Autumn. I don't see any questions in the chat. Tony, do you have any raised hands?

TONY HENRIQUEZ: I don't see any raised hands right at this moment and I think the only thing I have is the clarification from Ms. Regina Rieger -- I'm sorry, not a clarification, she was saying thank you for the clarification on the N/A applicable rate schedule on slide 75. So --

KOJI KAWAMURA: Okay.

TONY HENRIQUEZ: -- all I have.

KOJI KAWAMURA: Okay. So let's on go ahead and open up the phone lines. Okay. And I'm

going to go ahead and unmute Ryley. Ryley, do you have any questions?

RYLEY KELLY: No, no questions. Thank you.

KOJI KAWAMURA: Thank you. All right. So let's go on ahead. Seeing there are no additional questions, let's go on ahead and move to the next presenter.

MS. WOLFE: Okay. So the next presenter is Ms. Rosemary Jones. She's our power marketing and energy services specialist and she will share information on the sale of surplus products.

ROSEMARY JONES: Okay. Next slide. Good afternoon. I'm Rosemary Jones, power marketing advisor. Sierra Nevada is aligning our rates schedules with the rest of WAPA by using sale of surplus products, normal rate schedule for grouping energy, frequency response, regulation, reserves, and resource efficiency together in our current rates process.

Surplus products are available after meeting statutory operational and SBA requirements and after the power marketing program allocations happen in the two-day ahead process. It does not include boat transmission or BA balancing in real time,

although the rate schedules may apply to pre-owned contracts.

Surplus products are only available under specific conditions. One, under a rate schedule; two, the product or program design does not impact statutory requirements, operations, SBA balancing or base resource availability and maintains water neutrality; three, availability is based on varying conditions and limitations; and four, all sales surplus products are under agreement or contract with WAPA. Sierra Nevada has been engaging in the following surplus product sales as a benefit to our customers. PRR costs: During this time, reclamation from WAPA have worked to remain water neutral in providing surplus products. Next slide.

Okay. Autumn has asked me to present the sale of surplus products proposed rate schedule, SVSSP1. For component one, WAPA SNR shall determine the charge for each product at the time of sale to either the greater of WAPA Sierra Nevada's costs or market rates to include transmission charges. WAPA Sierra Nevada shall use a separate agreement to specify the terms of the sales.

The customer may be responsible for acquiring additional transmission service necessary to

deliver the products for which a separate charge may be incurred from the transmission provider.

Next slide, please. Save. So the products that we are currently doing. Current products were presented to our customers before pilot testing occurred. (Inaudible) was a collaboration between WAPA and its customers at the Sierra Nevada customer coordination committee meetings. These initial products have provided roughly $49 million in revenue. I will now briefly review the current products and then present frequency response and resource sufficiency.

Under the energy heading, is -- first, is (inaudible) During the one-day ahead training process, Sierra Nevada trader purchases energy in the lower price off-peak hours and sells the energy is the higher priced peak hours by moving the water from the off-peak hours to the peak hours. The trader receives bids for buying and adjust for any transmission or transaction cost and selects the lowest total cost bid. Utilizing a set of price forecast tools, including adjustments for transmission or transaction cost, the trader compares offers against the adjusted forecast price in our tools to determine the best offer.

The buy and sell positions are sent by email to our WSTP trading partners under agreement with WAPA and follows in the proper risk rating as determined by Sierra Nevada's risk management committee and/or may be purchased and/or sold within the Cali ISO day-ahead market.

Additional energy may happen when there is a day ahead or real time generation change. Infrequently, declamation will contact resources or real time merchants and request a sale of energy for water balancing requirements to avoid spilling the water.

Next is spinning reserves. Our (Inaudible) Spinning reserve are available to adjacent BA trading partners or the Cali ISO day-ahead market. Sierra Nevada bids the energy at the top of the market rate of $1,000 and the capacity of the Cali ISO day-ahead capacity price. Most of the spin capacity has been sold to the Cali ISO market and while the energy has been dispatched, it has only happened a handful of times, mainly during Cali ISO reliability testing. Regulation up/down product is only transacted with Cali ISO and at this time we have determined just regulation up is beneficial. Regulation down is currently on hold due to the complexity of providing

it to the day-ahead market. Those are our current products. Next slide, please.

Frequency response reserve. With the expected retirement of (inaudible) requirement 2 that mandates 50 percent of an entities contingency reserve are held as spinning reserve. BANC working in collaboration with the WAPA SPA developed a new approach for meeting the BA's reserve obligation, Frequency response reserve or FRR.

At present time, the retirement (Inaudible) -2A is on indefinite hold by (Inaudible). Our BANC is going to take part in local trials this November. Failing (inaudible), FRR would result in the BAA being penalized. Next slide. FRR has a spinning capacity that responds to frequency deviations within 30 seconds and maintains response for at least 2 minutes until frequency deviation is corrected. Automatic response is a requirement for BA generators to correct frequency deviation with no operator intervention. FRR has contributed -- FRR contributed is based on .1 Hz deviation from scheduled frequency, typically 60 Hz. The most severe single contingency or MSSC requires sufficient reserve capacity to recover from the MSSC as it does today.

Sierra Nevada's MSSC will continue to

be 100 MW and will continue to require spinning capacity. Today we have 50 MW of spin and 50 MW of non-spin to meet our MSSC. In the future, FRR spinning capacity will be 11 MW and contingency reserve will be 89 MW. This lowers the amount of spinning reserve required to be online for operation by 30 MW. However, this does not equate to an increase of surplus capacity. Presently, we do not have assumptions or predictions on the level decrease we may see from spinning reserve. Expectation is -- there's a heavy dependence on water level and drought conditions which contribute to surplus products. Next slide, please.

CPV units can provide FRR. Generators can also provide FRR or so. WAPA Sierra Nevada is planning to explore selling any surplus FRR to neighboring BA SBAs in the Cali ISO. FRR could be offered the same as spinning reserve today and will be at a similar rate. It is predicted that frequency response will be more valuable than spinning reserve. Implementation is planned for April 2021 at this time; however, there may be an opportunity to implement earlier based on generator response testing results. The USBR is requesting acceleration of implementation to conserve water this year. Next slide, please.

Resource efficiency is not a regulation-type product. It is capacity (inaudible), shown to the market through an energy bid which market awards might dispatch. The IM entities must show they have adequate capacity to balance load and manage contingencies through the resource efficiency evaluation series of four tests: balancing, bid capacity, flex ramp, and feasibility. The five participating BANC members including WAPA passed or failed resource sufficiency tests at a -- collectively as one BAA.

WAPA intends to offer surplus capacity to be available for either test at the discretion of the purchaser. The surplus capacity will come from moving current sales of surplus products such as regulation and spin, by not offering these to the Cali IOS day-ahead market as we do today, and instead, using the capacity as the resource efficiency product. With the rate schedules for regulations, spin, and resource sufficiency align we do not expect a decrease in benefits by making this change.

Sierra Nevada is looking at agreements or contracts for an annual product as well as an additional product during the one day ahead trading period. It is expected there will be hours when

Sierra Nevada does not have surplus product for sale, and in fact, an early study has shown there will no flex ramp-up available June through September, hours 20 to 23 while this merchant will be responsible for selling and scheduling the resource sufficiency balancing product.

WAPA will address the energy behind the capacity in a similar fashion to the energy behind spin that may produce additional benefits if the market call is equal to or greater than WAPA's bid price. There have been times when the prices have been set to the cap of $1,000 for 15 minutes. Sierra Nevada by reclamation will address water usage to ensure water neutrality just as is done for our current programs today. Next slide.

Resource sufficiency supplies -- resource sufficiency balancing product supplies a resource movement in the direction necessary for the BA to pass the balancing test. The hourly balancing test ensures the BAA has the capability of balancing resources to load for each operating hour to avoid leaning on neighbors.

Working together is mutually beneficial to avoid penalties. Passing the balancing tests protects all members including WAPA from

potential market penalties for under and over scheduling. Resource sufficiency balancing helps to resolve generator imbalance and energy imbalance by meeting the market balance test that (inaudible) is supporting.

The proposal for offering resource sufficiency balancing products through the merchant is designed to cover any cost that may be incurred by WAPA for supplying the product, making it cost neutral. A benefit comes from penalty cost avoidance as well as any energy sales which are priced to be sold and dispatched by the market. Next slide, please.

Resource sufficiency flex ramp products shows the available capacity through energy bids beyond the required resources in the balancing test, also known as base schedule. The 15-minute flex ramp ensures the BAA has the sufficient ramping capability to meet forecasted uncertainties such as demand, unobstructed deviation or forced outages. Market design does not let capacity that is used for balancing to count for passing the flex ramp; therefore, the resource sufficiency product cannot be used for both tests in the same hour.

WAPA will ensure energy bids are

sufficient to meet our flex ramp capacity requirements ahead of surplus sales. Flex ramp is extremely to predict with 100 percent accuracy so just by all BANC members' best efforts, it is possible the BAA will fail occasionally. Failing flex ramp results in no EIM participation for the next 15 minutes or longer until the test is passed and financially equates to lost opportunities to realize dispatch benefits from the market. (Inaudible) has seen very infrequent failures at a single interval level during their participation.

We do expect more opportunity to participate in -- in the EIM with this change and any additional revenues will go to the PRR. These revenues may happen if the EIM markets clears at or above our bid price. We intend to achieve water neutrality each day. We will continue to deliver our firm product as we do today and beneficially optimize the value of the hydropower resource of the CVT system in our real time. Once EIM -- once an EIM, Sierra Nevada will continuously elevate the resource sufficiency product and amount of capacity available as well as benefits. There will be transparency reporting and communications with the customers at the customer meetings as happens today with the other

surplus products.

So coming up next is Mr. Robert Delizo, SNR's resources and prescheduling manager and he will present where resource sufficiency products fit in the generation range dispatch. We will now go to Koji.

KOJI KAWAMURA: Thank you, Rosemary. Does anyone have anything else? Any questions in the chat? Tony, did you have any raised hands?

TONY HENRIQUEZ: I do. I have one raised hand. Let me go ahead and bring up Ms. Regina Rieger. Let's see. Go ahead, Regina.

REGINA RIEGER: Thank you. Thank you for your presentation, Rosemary. My question relates to slide 86. There's a reference to 11 MW of frequency response reserve. Can you clarify -- is that the surplus product or is that the sub BA requirement?

ROSEMARY JONES: That is the sub BA requirement. So on the left is the current requirement and on the right, under FRR, will be the requirements.

REGINA RIEGER: Is there a specific charge for that frequency response reserves related to the FDA? ROSEMARY JONES: I would have to ask Autumn.

AUTUMN WOLFE: Okay. So for frequency response reserve, there's still not a market necessarily for it. And until we start seeing a market for it, we will use our existing spin rate for FRR, but then as soon as we see a market developed for frequency response reserve, then we will use the existing market rate -- the greater of the existing market rate or what was our cost.

REGINA RIEGER: Okay. So clarification on that point. Is that related to the surplus product?

AUTUMN WOLFE: Yes. I'm sorry. Is that what you were speaking to? I thought you were speaking to the surplus product that we would market under the sale of surplus products.

REGINA RIEGER: It didn't sound like the 11 MW that's referenced on slide 86 is a surplus product but a sub BA requirement.

AUTUMN WOLFE: Oh, the sub BA requirement. So you're asking what we charge the sub BA for the 11 MW?

REGINA RIEGER: Correct. And I guess my analogy would be to potentially regulation, right. There's a regulation requirement in the sub BA.

AUTUMN WOLFE: Okay.

REGINA RIEGER: Yeah. So if there could be an analogy there to what this frequency response reserve requirement looks like in the BA -- sub BA.

AUTUMN WOLFE: Okay. So I'm going to have to do some more research on that and we can definitely write your question down and provide a formal response to that at a later time. I apologize for not having that right off the top of my head here. I apologize.

REGINA RIEGER: Thank you.

AUTUMN WOLFE: Thank you.

KOJI KAWAMURA: Okay. Do you have more questions, Tony?

TONY HENRIQUEZ: I do not see any on the chat or raised hands and if I --

KOJI KAWAMURA: (Inaudible) cell phone.

TONY HENRIQUEZ: Okay. We'll let you know. Okay. So I am unmuting -- Ryan, do you have any questions -- Mr. -- excuse me -- Ryley Kelly?

RYLEY KELLY: Nope. No questions.

TONY HENRIQUEZ: Thank you. And then I have one other -- sorry.

KOJI KAWAMURA: Go ahead.

TONY HENRIQUEZ: I have one other call-

in user -- recent call-in user, number 27. Let's see. Phone number 916-934. Do you have any questions? I heard you briefly but I guess not. Okay.

KOJI KAWAMURA: Okay. Seeing there are no questions so let's go on ahead and move on to the next presenter.

AUTUMN WOLFE: Okay. So next up, as Rosemary mentioned, we have Robert Delizo, our resources and scheduling manager and he will share information with us on the EIM generator dispatch (inaudible). Thank you, Robert.

ROBERT DELIZO: All right. Can you guys hear me?

AUTUMN WOLFE: We can hear you. Thank you. ROBERT DELIZO: Okay. So I was planning to share my screen but it doesn't look like I can do that for now. So go ahead and just manage with using the pdf. So the goal of this presentation is to give demonstrate the allocation of the CVP generation as far as bidding resources under EIM.

So first let's look the allocation of the CVP generation as it correlates with the current (inaudible) test and is not (inaudible) for one hour.

It's shown here for CVP generation at flat level and also the full demand. References for

the flat levels are the (inaudible) shown where EIM resources and demands are also grouped into corresponding EIM demand components at the bottom.

So first, we found out -- through that column on the table above shows the generational schedule for the hour at the flat level. So the high megawatts represent the maximum capacity available from the online units and the low megawatts represent the minimum generation level based on operational constraint.

So in this case, Trinity number 2 -- that unit has 10 MW of demand and also (inaudible) the generation corresponds to meeting environmental requirements. So for (inaudible), both the high megawatt and low megawatt are set by your schedules. So besides the CVP generation other elements of existing contributors to the WAPA FCA balancing position leading to EIM timeline are the import schedules, our export schedules, the load in the FBA, as well as the WAPAs. If you need more details for imports, this will be representing capital/loss paybacks, emergency paybacks due to WAPA, including purchases that will sink into the FDA.

For demand, the exports could be project case load and the ISO BAA. Also first

reference load's in there. Also base resource that is imported to the ISO as well. Also exports can be the base resource allocations for customers that are in the ISO as well as in BANC or GID. So -- and also exports could be the emergency paybacks that emanate from SMR FDA. The purchases that are not used by (inaudible) -- that also gets imported into the (inaudible). And from the point of view of the FBA, those are exports as well.

That is also true for the (inaudible) sales and real time purchases that sink outside of the SBA. So in terms of load -- we kind of touched on this earlier. These are projects (inaudible) load in the FBA like (inaudible) pumps, first preference load in the FBA like Trinity (inaudible) district loads. Full load service and basic (inaudible) customers in the FBA and of course, the (inaudible).

So in the table below, DDR -- that pertains to nonconforming load that are modeled as NGRs of dispatchable demand resource time that WAPA does not intend to submit reprise bids so they are not going to be curtailed by the ISO. Their basic schedules will be treated as self-schedules under EIM and this was mentioned earlier are the Lawrence (inaudible) load and (inaudible) load.

Of course, lots of here pertains to the COTP lost forecast. A load pertains to the small loads in the FDA -- that CPUD load -- and the interchange are basically the net of the imports and exports. And as mentioned earlier, we are not exporter of energy from the FDA.

So to the following is the illustration of how we would determine the EIM bid range for (inaudible), it being 75 as one EIM resource. So as shown here on the expected demand, I think -- Sonja, if you're controlling it, you can go ahead and click. So the (inaudible) accounts for the regulation down at capacity for the FDA.

Go ahead and click some more. Okay. That's good. So the (inaudible) accounts for the 60 MW of regulation down, capacity for the FDA and the (inaudible) accounts for the 60 MW of break-up capacity for the FDA as well as our contingency reserves. These are capacity (inaudible) so we'll not dispatch for (inaudible) energy under EIM.

So we -- maximum bid range between 130 MW and 1508 MW. So WAPA fixed schedule here -- we'll need to fall within this range and as you can see, that is represented by the red line for the -- WAPA is 438 MW. Okay. Keep going. Let's go to the next

slide.

This slide takes into account the proposed resource sufficiency product assuming there's still megawatts of regulation capacity that is available. That capacity will be allocated for use in EIM. Under this premise, the base schedules for reg up and reg down will be 50 MW and this will result in an expanded bid range for WAPA's participating resources.

As an example, WAPA may adjust the schedule for the generators up if that is needed to compensate for another member's short position in case of generator's basic schedule. This way, BANC as the EIM entity, will pass the balancing test of the resource sufficiency test. And as Rosemary mentioned, the expanded bid range will also provide more capacity for use in the flex (inaudible) test of the resource sufficiency test.

Some more. So basically, you can see here that the mid-range is now between 120 MW and 1,518 MW. And that expansion of the mid-range is attributed to us moving the 10 MW of (inaudible) product into EIM. All right. So let's go to the next slide.

This slide shows a particular day in

our EIM resource dispatch simulation. It shows how the incremental and decremental dispatches keep a water- neutral operations at the end of day.

So the green columns represent the aggregate energy for the hour, and the gold columns, basically, represent the (inaudible) energy for the hour. The blue line represents the cumulative net energy from incremental and decremental dispatches and as you can see in hour 24, that ends at zero. The maroon or brown and blue areas use the secondary scale on the right. They represent the sale benefit and purchase benefits, respectively. And the light blue area is the sum of both the sale and purchase benefits for this capacity.

So this is basically representing the 50 MW of approximate resource that we ran in our simulation and a similar chart is prepared for the 10 MW of capacity that we intend to move from regulation to EIM.

So let's go to that in the next slide. So similarly, this is the potential dispatch and associated benefits of the 10 MW capacity proposed for the resource sufficiency product. The chart components are the same as the previous slide. The scale values are different, but again, the intent here

is the blue line starts close to zero at the same time and goes to zero at hour 24.

So that concludes the presentation on DIM generator dispatch ranges. I'd be happy to answer questions at this time.

KOJI KAWAMURA: Thank you, Robert. I don't see any questions appearing in the chat. Tony, do you see any raised hands?

TONY HENRIQUEZ: I don't see any raised hands at this moment. I'm checking to see if there's anything on chat. Nothing on chat.

TONY HENRIQUEZ: Okay. So let's go ahead and open up the phone line. Okay. Ryley Kelly, do you have any questions?

RYLEY KELLY: No questions. Thank you.

TONY HENRIQUEZ: Thank you. And then I have call-in user 27 with phone number 916-934. Do you have any questions?

ADAM SANTINO: Hi, Tony. This is Adam Santino. I don't have any questions.

TONY HENRIQUEZ: All right. Thank you, Adam.

KOJI KAWAMURA: Let's see. No additional questions. Let's go on ahead and move to the next presenter.

AUTUMN WOLFE: All right. Next slide, please. Okay. So this takes us to the end of our presentation for today. Next slide, please. I'd just like to share these additional resources with you. These are some of the websites with links to our website for our rate case -- for rate case 194. And then we have our SNR EIM information webpage where we share a little bit more information on participating in EIM.

And so if you have any questions you would like to follow up with us on, please feel free to contact us using our SNR rate case email address that's here on the bottom on the screen. The email address is SNR, dash, rate case, at WAPA, dot, gov.

And with that, I'll go ahead and turn it over to Koji for closing remarks.

KOJI KAWAMURA: Thank you, Autumn. I would just like to remind everyone that we will holding a public comment forum at which WAPA will receive oral and written comments. This comment forum will start in around 20 minutes, starting at one o'clock Pacific time today.

In addition, at any time during the comment period, you may submit written comments to WAPA. All written comments must be submitted prior to

the end of the consultation and comment period. Consultation and comment period closes on October 29th, 2020. Written comments should be sent to Ms. Sonja Anderson, Regional Manager, (Inaudible) Power Administration, 114 Parkshore Drive, Wilson, California, 95630. Email: snr, hyphen, rates case, at WAPA, dot, gov.

So I want to thank everyone for attending this forum. If you have -- and I think -- thank you for attending this forum and your interest and participation. And with that, I'm going to go on ahead and close the public information forum and we will see you in 20 minutes for the public comment forum. And with that, we'll go off the record for the information forum. Thank you everyone.

(Break)

KOJI KAWAMURA: All right. If we can go on ahead and go back on the record.

Good afternoon, everyone, and welcome back to WebEx for Western Area Power Administration's public comment forum. Those formula rates for the energy balance market service, sale of surplus product, and revisions to the existing energy and balance generator, and balance rate schedules. Rate order, RAPA number 194.

My name is Koji Kawamura. I'm attorney with WAPA's office of general counsel and I'm going to be presiding as moderator for today's comment forum. Most if not all of you should have received a letter or email from WAPA informing you of today's public comment forum. WAPA also published a notice of today's comment forum in the July 31st, 2020, Federal Register, Volume 85, page 460.

AUTOMATED VOICE: This meeting is being recorded.

KOJI KAWAMURA: Federal Register, Volume 85, Page 460-03. And a copy is also on WAPA's website.

Finally, WAPA provided notice of this public comment forum at the public information forum which was held earlier today. We are meeting today for a public comment forum. As noticed, the purpose of this comment forum is to give interested parties the opportunity to make oral presentations or to submit written comments on the proposed formula rates.

If you don't have oral or written comments prepared for today's public comment forum, you can submit them at any time during the comment period. These comments should be addressed to Ms. Sonja Anderson, Regional Manager. The comment period

ends on October 29th, 2020. All comments must receive by that date to be assured (Inaudible).

I want to make sure that everyone's aware, there are verbatim transcript of today's forum that is being prepared by our court reporter. Everything said while we were in session today, together with all presented documents, will be part of the official record. You can purchase a copy of today's transcript directly from the court reporter. The court reporter's name, address, and telephone number are available from WAPA by request. Copies of the transcripts will also be available for review at WAPA Sierra Nevada customer service (Inaudible) and on the website.

Because of COVID, we're still avoiding large in-person meetings and I want to thank everyone for attending this virtual meeting. Given the logistics of a very large meeting, to avoid microphone feedback, we are muting everyone but the speaker. If you have questions or comments that you want to bring up today, please raise your virtual hand or you can notify us that you want to talk in -- by putting a note in the comment section.

If you don't have access to the web and are participating by phone, we will open up the phone

lines after we go through the hands and the chat questions -- or the comments, I mean. I wanted to make sure that we get an accurate attendance of today's record -- strike that.

I want to make sure we get an accurate record of today's attendance and so if you have signed in via the web interface, we already have your name and contact information and the organization you represent. If you haven't signed in via the web chat or via the web, I'm going to open up the phone lines now we can have you identify yourself and identify who you represent.

Tony, if there are any people on the phone -- if you can go ahead and open up the phone lines for them.

TONY HENRIQUEZ: Okay. So this is Tony Henriquez. I am checking to see -- I'm going to go ahead and open up the phone line and it looks like the only line that I have is -- I believe it's Ryley Kelly. Ryley, will you go ahead and state your -- all your information, please.

RYLEY KELLY: Yeah, hi. My name is Ryley Kelly. I'm an electric business analyst on the power supply team of the city of Roseville.

TONY HENRIQUEZ: Thank you, Ryley.

That's the only line that I have, Koji.

KOJI KAWAMURA: Okay. Great. Thank you, Tony. All right. So just in terms of the process, after we've -- if you want to comment, just go on ahead and drop a note in the chat or raise your hand. Then we'll go on ahead and start. As the hands are raised, I will go on ahead and take those comments. You will have the opportunity to present your comments. And like I said, if you don't have comments prepared today, you can present them at any time during the comment period.

And just a reminder that all comments should be relevant to the proposed rates. As a moderator, I do reserve the right to disallow comments that aren't relative.

And I'd like to take a moment to introduce the panel. We have today with us Arun Sethi, WAPA's power marketing manager; Autumn Wolfe, WAPA's rates manager; Mark Lynch, a rate specialist; Jody Wooten a rate specialist; Corrie Stewart, a rate specialist; and other subject matter experts may also be available. So at this point time, I'm going to go on ahead and open up the floor. I'm not actually seeing any questions in the chat. Tony, do you have any hands raised?

TONY HENRIQUEZ: I do not see any raised hands at this time and I do not see any on my chat inbox.

KOJI KAWAMURA: Okay. Well, why don't we just give it another minute and let people think about it, and if not, I'm going to go on ahead and prepare our closing remarks here.

All right. So seeing that there are no comments today, I just want to remind everyone that you can still submit written comments. All written comments must be submitted prior to the end of the consultation and comment period to be sure for consideration. The consultation and comment period ends on October 29th, 2020, and written comments should be sent to Ms. Sonja Anderson, Regional Manager, Sierra Nevada Region, Western Area Power Administration, 114 Parkshore Drive, Wilson, California, 95630, or you can email them to snr, hyphen, rate case, at, WAPA, dot, gov. After the close of the public comment period, WAPA representatives will review all the information in the comments and documents that have been received with regards to this process. WAPA will then announce its decision in the Federal Register at some point after the close of the comment period. All comments

including those made during the comment forum will be discussed in this announcement.

I want to thank everyone for attending the public information forum and the public comment forum, and if you have not already done so, you know, please take this last opportunity to identify yourself for the record. Tony, is there any additional people on the phone that have joined in?

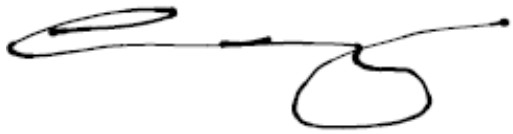
TONY HENRIQUEZ: I do not see any others other than the one.

KOJI KAWAMURA: Okay. All right. Well, with that, then I want to thank everyone for your interest in this proceeding and thank you for attending today. We're going to go ahead and close the public comment forum and -- you're more than welcome to submit comments -- written comments -- as described above and described in the Federal Register notice. Thank you and we can off the record now.

(Whereupon, at 1:00 p.m., the proceeding was concluded.)

CERTIFICATE OF NOTARY PUBLIC

I, Gigi Lastra , the officer before whom the foregoing proceedings were taken, do hereby certify that any witness(es) in the foregoing proceedings, prior to testifying, were duly sworn; that the proceedings were recorded by me and thereafter reduced to typewriting by a qualified transcriptionist; that said digital audio recording of said proceedings are a true and accurate record to the best of my knowledge, skills, and ability; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this was taken; and, further, that I am not a relative or employee of any counsel or attorney employed by the parties hereto, nor financially or otherwise interested in the outcome of this action.



Gigi Lastra
Notary Public in and for the
State of California

CERTIFICATE OF TRANSCRIBER

I, Sonya Ledanski Hyde, do hereby certify that this transcript was prepared from the digital audio recording of the foregoing proceeding, that said transcript is a true and accurate record of the proceedings to the best of my knowledge, skills, and ability; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this was taken; and, further, that I am not a relative or employee of any counsel or attorney employed by the parties hereto, nor financially or otherwise interested in the outcome of this action.

Sonya Ledanski Hyde

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